PERFORMANCE CONSIDERATIONS FOR HORIZONTAL AND UNCONVENTIONAL WELLBORE CONFIGURATIONS

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A

THESIS

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ABSTRACT

The goal of this study was to investigate the performance of horizontal and unconventional well configurations and formulate guidelines for selecting optimum configuration. The simulation model was validated by comparing the productivity of numerical model for a horizontal well with the analytical models. The productivity of horizontal, snake wells and fishbone wellbore configurations was studied by varying four parameters, vertical position of well in the payzone, permeability anisotropy, partial completion and well length. Effect of friction loss correlations on estimation of well productivity losses was also studied.

The study concludes that the ratio vertical position of well, Zw to the payzone thickness, h decreases the productivity of the wells increases. There is no significant change in performance of the wells for different configurations. As the permeability anisotropy ratio decreases the productivity decreases. The cumulative production does not decrease by half when the perforated well length is decreased by half. Also, the productivity index increases with increase in well length.

Based on the results obtained we formulate guidelines for selecting well bore configurations. The results of this study can be applied to the design of horizontal and unconventional well configurations to aid reservoir management.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

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1. INTRODUCTION

The major purpose of drilling horizontal and multilateral wells is to enhance reservoir contact and thereby enhance well productivity. In situations with a high risk of gas or water coning, horizontal wells may be an attractive alternative to vertical wells. Because of the great directional control that can be currently achieved in drilling horizontal and multilateral wells, they may also be of great use to link a well with productive parts of the reservoir.

The productivity of a horizontal well depends on various factors such as length of the well, well orientation, well configuration, well location in vertical and areal direction, perforation distribution, pressure drop in the wellbore and various reservoir parameters including distance from oil water contact, type of drive mechanism, permeability anisotropy etc. Various researchers have proposed models either analytically or using reservoir simulation or using the combination of both, to study the effect of these parameters on the well productivity.

This study uses numerical simulation to evaluate the performance of horizontal and unconventional configurations. Three basic configurations studied are horizontal, snake and fishbone. Four parameters used to analyze the productivity of well configurations are, vertical position of well in the payzone, permeability anisotropy ,partial completion, well length and pressure drop in the wellbore. To study the effect of well vertical position, a payzone of 100 ft thickness located centrally between the oil-water contact of the reservoir is considered and the location of the wellbores is varied in this vertical section. K_v/K_h ratios of 0.1 to 0.0001 are used to study the effect of reservoir heterogeneity, locating wellbores centrally in the payzone. Similarly for centrally located wellbores, three completion scenarios are analyzed. These are, wells perforated at heel and toe, wells perforated at the center and wells uniformly perforated along the lateral section, keeping the effective perforated length constant. To study the influence of well length, the PI of unconventional well configurations is compared with the PI of horizontal well for different well lengths. The vertical anisotropy of the system for this study is varied arbitrarily. The effect of pressure drop in a horizontal well bore is indirectly dealt with by evaluating impact of various friction factor correlations on the productivity index of the horizontal well. Finally the objective is to provide guidelines for selection of optimum wellbore configuration.

1.1 Objectives of this work

1. To review methods for evaluating productivity of horizontal, multi-lateral and unconventional well configurations.
2. To apply inflow performance method to study wellbore configurations using field case and to study the effect of placement of wells, permeability anisotropy, partial completion, well length and pressure drop on well performance.
3. Analyze the results of the case studies and develop guidelines to support decisions on the optimum well configuration.

1.2 Scope of this work

1. Calculation of the initial steady-state and pseudo-steady state well productivity of different wellbore configurations. Configurations studied are horizontal wells, multilateral and snake wells.
2. Productivity index and cumulative production were calculated for the field case considered.

2. LITERATURE REVIEW

Three methods used to evaluate the performance of horizontal and multilateral wells are,

1. Well Test Analysis
2. Inflow Performance Studies
3. Numerical Reservoir Simulation

In this chapter we review the literature to evaluate methods used to study the performance of horizontal, multilateral and unconventional configurations and the impact of different aspects such as well configurations, reservoir heterogeneity, drainage area shapes, well locations in areal and vertical plane, pressure drop along wellbore, partial completion on well productivity.

The focus of literature review is on inflow performance and reservoir simulation methods for evaluation of well performance

2.1 Inflow Performance Studies

Joshi (1987) provided a method to predict the performance of horizontal wells and drainholes. The author assumed steady state flow of a single phase fluid. Joshi considered the horizontal wells and drain holes as infinite conductivity fractures. Joshi also studied the influence of reservoir height, anisotropy, eccentricity and elevations of wells on productivity. Joshi (1988, A) provided production forecasting methods for horizontal wells based on analytical solutions and correlations of numerical model results. In the same year, Joshi (1988, B) also described theoretical calculations to predict effective wellbore radius and effective skin factors of horizontal wells. Joshi also studied the comparison of productivity indices of horizontal wells, slant wells and vertical wells in a constant drainage area. Joshi and Raghavan (1990) presented procedures to estimate the productivity of multiple drainholes emanating from vertical wellbore or multiple fractures intercepting horizontal wells.

Mutalik et al (1988) presented a technique to forecast the production from fully penetrating, infinite conductivity vertical fractures and horizontal wells located centrally or offcentrally in an areal drainage plane, in rectangular drainage areas. Mutalik et al calculated dimensionless time at which pseudo steady state begins for such wells and used analytical pressure transient solutions to calculate shape factor, C_A and corresponding equivalent skin factor, S_{CA}. Mutalik et al found that the pseudo-steady state shape factor and skin term, for the horizontal well approaches a fully penetrating infinite- conductivity vertical fracture for large values of dimensionless well length. Thus knowledge of shape factor and corresponding pseudo-state time would facilitate calculation of horizontal well production forecast from a corresponding infinite-conductivity, fully penetrating vertical fracture forecast.

Babu and Odeh (1989,A) presented an equation for calculating horizontal well productivity index identical to that of vertical well productivity index. This equation calculates pseudo-steady productivity. The equation is used to study effects of well length, location, degree of penetration and permeability anisotropy on well productivity.

Goode and Kuchuk (1990) provided formulas for evaluating the inflow performance of horizontal wells in a rectangular drainage region bounded from above and below. The upper boundary may be no flow or constant pressure. The well can be placed anywhere in the drainage volume and can be of any length. The formulas derived are applicable over a wide range of practical interest for a variety of reservoir geometries.

Dikken (1990) was the first to develop a model that coupled turbulent flow in the wellbore to flow in the reservoir. The model links single-phase turbulent well flow to stabilized reservoir flow. The resulting second order differential equation is solved numerically for appropriate boundary conditions. For cases with laminar flow Dikken developed analytical equations both for an infinite and a finite length well. But for cases with turbulent flow along wellbore, Dikken developed analytical equation only for infinite wells and for finite length wells he solved the equations numerically. Dikken demonstrated the importance of friction in horizontal wells and showed how influx per unit length keeps decreasing with well length, because of frictional effects.

Kuchuk et al (1992) presented formulas for evaluating the inflow performance of horizontal wells in vertically layered reservoirs with crossflow. Kuchuk et al also outlined a method of selecting a well location in the layered system for maximizing productivity. They developed analytical methods for transient, pseudosteady and steady state productivity indices for horizontal wells in a rectangular region with no flow or constant pressure boundaries.

Simple analytic tools were presented by Kabir (1992) for predicting the inflow performance relationship for horizontal or slanted wells producing from a solution gas drive reservoir. He also showed that once the absolute open flow potential or the maximum flowrate is properly evaluated, Vogel and Fetkovich correlations, originally intended for vertical wells can be used to describe a well's IPR regardless of its orientation. The absolute open flow potential can be computed by using any productivity index expressions developed for horizontal wells for various boundary conditions.

Goode and Wilkinson (1991) developed an analytical model to predict the inflow performance of selectively completed horizontal well. They assumed the distribution and number of open intervals are arbitrary as well as the position of the well in the drainage volume, provided that the distance from any open interval to a lateral boundary is large. They concluded that open length of the well can be reduced considerably without a substantial decrease in productivity.

Economides et al (1994) presented performance relationships for unconventional well configurations including early time and late time differences rather than only bounded flow regimes. Economedes et al presented solutions for arbitrarily oriented singe or multiple horizontal wells along with the discussion of well known existing relationships.

Ihara et al (1993) studied the effects of accelerational pressure drop on horizontal well productivity. Ihara et al improved an initial model by including accelerational pressure drop in the wellbore. Frictional pressure drop and liquid hold up were determined numerically by using the individual flow model corresponding to the flow pattern as predicted by the mechanistic model. Effects of inflow perforations on the wall friction factor were not taken into account.

Landman et al (1993) used a special function called the Gauss hypergeometric function to obtain an analytical solution for a finite well with turbulent flow. It was an enhancement to Dikken's (1990) model. Landman et al demonstrated graphically how the ratio of pressure drop in the wellbore to drawdown at the heel of the well could be related to productivity loss due to friction. Landman et al also developed a methodology to calculate the optimal perforation density to obtain constant specific flow into the well.

An statistical approach of analysis was presented by Faruqi et al (1995) for performance evaluation of horizontal wells in bounded anisotropic reservoirs. They presented a statistical model to calculate horizontal well shape factor and the fraction of horizontal well length contributing to unrestricted production. Their model can be used to evaluate performance of horizontal wells without the need to use complex numerical and analytical solutions.

Novy (1995) provided a simple formula to calculate effect of frictional pressure drop could cause on productivity. Novy's work is an extention of work done by Dikken (1990). He solved the equations numerically for it provides an engineer with easy-to-use criteria for judging whether friction reduces productivity by 10% or more in particular wellbore/reservoir system. Novy did not account for accelerational or inflow effects of the fluids. Novy stated that a convenient thumb rule in the case of laminar flow, that friction reduces well flow rate by at least 10% when the wellbore pressure drop is greater than 15%. He also guessed that this rule was independent of the reservoir well properties.

Ozkan et al (1994) presented a procedure to compute the flux distribution and the wellbore pressure at the heel of the horizontal well. They developed a semi analytical model, using Green's function to describe reservoir flow. The model cannot be used when the reservoir is not infinite acting. The model offers flexibility for choosing any type of the traditional pipe flow friction factor correlation in calculations of pressure drop. They represented their results in dimensionless form for a single-phase liquid flowing in the system.

Recently, Shedid et al (2001) studied the sensitivity of different parameters to that of horizontal well productivity. Their study's main objective was to develop a comprehensive evaluation of currently used steady state productivity equations of horizontal well. Shedid et al investigated the effect of productivity effect of horizontal well length and pay zone thickness on the productivity ratio of horizontal to vertical well having identical drainage areas flowing under identical flow conditions they studied the influence of pressure drop on production rate of horizontal wells.

2.2 Numerical Reservoir Simulation

A reservoir simulator can be used to predict future oil production from a horizontal well. However, using a reservoir simulator can be costly and time consuming. To overcome this difficulty, Plahn et al (1987) developed a set of type curves to forecast oil production from horizontal wells at their maximum rate with constant bottomhole pressure from homogenous, isotropic solution gas drive reservoir. The curves were developed by correlating the results of 48 simulation runs. The input data used in the simulation runs was chosen it would encompass wide range of PVT properties, relative permeability characteristics, rock properties, and well dimensions. These curves can be used to screen candidate reservoirs for horizontal drilling possibilities.

Stone et al (1989) developed a fully implicit, three dimensional, thermal numerical model for simulating flow through a porous media and through a wellbore. The reservoir model consists of four equations satisfying conservation of energy, conservation of mass and phase equilibrium constraints. Reservoir equations were solved using finite difference approximations. A simple multiphase flow model in the wellbore was used to obtain stable wellbore calculation. Flow regimes include stratified, bubbly, slug and mist flows. Well grid block pressure was related to reservoir grid block pressure through a Peaceman type well model. Wellbore grid blocks are embedded in reservoir grid blocks. The coupled model was targeted mainly at horizontal well or other applications in which a high degree of dynamic interaction occurs between the wellbore and reservoir like gravity drainage. Stone et al reported that flow regime calculation was stable unless flow rates occurred at transition from one regime to another. They found a reasonable match between their simulation results and experimental observations.

Islam and Chakma (1990) addressed the problem of both physical and mathematical modeling of horizontal wellbores including the effect of perforations. They used an experimental setup to observe flow through perforations. Flow rates used in experiments were high enough to induce turbulent flow conditions. Islam and Chakma measured pressure drop along the horizontal well both with and without perforations and the physics involved in that process. They reported that the perforations increased the pressure drop. The wellbore equations were presented in cylindrical coordinates and solved them using finite difference techniques. During simulations of the wellbore the bubble size and the number of bubbles entering the perforations was taken from their experimental study. The well model was coupled with a three-phase, compositional, hybrid simulator. Islam and Chakma reported very good agreement with experimental results and numerical results for low viscosity oils. For higher viscosity oils, a better match was obtained by assuming that the bubbles are being injected through each of the grid blocks as opposed to cluttering them in the first block. Islam and Chakma showed that not accounting for pressure drop in the wellbore would lead to overestimation of oil production rate and late estimation of gas/water breakthrough times.

Al- Haddad and Crafton (1991) compared the horizontal and vertical well productivities in fractured reservoirs with different matrix permeabilities. For this they used a two dimensional, two phase simulation model that uses single porosity formulation. The reservoir is divided into blocks that contain either matrix or fracture and the equations are solved implicitly to simulate naturally fractured reservoirs. The simulator is able to represent the transverse imbibition observed in the laboratory.

To study the performance of the horizontal well and slanted wells in an anisotropic medium, Besson (1990) generated type curves using a numerical simulator. For slanted wells Besson developed a pseudo skin factor which is matched with an analytically derived equation for a fully penetrating vertical well. Their calculations reveal that slanted well is less affected by anisotropy than a horizontal well.

Folefac et al (1991) reported that parameters such as well length, diameter, perforated interval have the most significant effect on the level of pressure drop in the wellbores. The proposed wellbore flow model is mechanistically based and it accounts for the distributed intake of fluid from the reservoir into the wellbore through the perforations. It also accounts for the inter-phase transfer between the liquid and gaseous phases. The plausibility of the model is verified by example calculations and comparison with production logging. The wellbore flow is based on a one dimensional drift flux analysis in which a mixture momentum equation is solved in conjunction with a drift flux expression for the slip velocity between the phases. The coupling and the wellbore flows can be treated implicitly or explicitly. The authors showed the that magnitude of pressure drop in the wellbore under two phase flow conditions can be almost twice that of single-phase flow under similar conditions. The authors concluded that pressure drop in the horizontal wells can be important when the well has high productivity index, a small well radius, a long perforated interval, and is flowing with two phases.

Brice et al (1992) claimed that when the Eclipse(1991) reservoir simulator was used to generate pressure profiles along the horizontal well, those predictions were much lower compared to those predicted by Dikken's model. However Brice et al stated that pressure drop in the wellbore obtained from production logging and pressure transient data matched well with Dikkens's model. After matching the results from Eclipse Simulator against those predicted by Dikken's model, they calculated pseudo-pipe diameters which can be input into Eclipse to yield the desired pressure drop in the well. Their results indicate that pressure drop along the well can increase coning. They reported that errors in simulations that of neglect wellbore pressure drop are large in cases with higher flow rates, high permeability and low viscosity.

Chang (1992) developed an inflow performance relationship through numerical simulation of vertical, horizontal and slant wells in solution gas drive reservoirs. He used a black oil simulator (BOAST-VHS) to generate curves for a single well in a 20 acre drainage area. The simulator was validated by comparing IPR simulations of a vertical well with a Vogel curve and then used to generate IPR curves for horizontal and slant wells.

Brekke et al (1993) developed a modular, comprehensive model of well and reservoir. Their model consists of a detailed horizontal wellbore flow simulator coupled to a reservoir simulator. Their horizontal well flow simulator (HOSIM) was linked to standard black oil simulator (RESIM) in an explicit fashion with a flow rate or bottom-hole pressure constraint imposed at the heel of the well. Both HOSIM and RESIM were run as stand alone versions and they both exchange information in an iterative manner until convergence criteria is satisfied in every time step. They account for frictional pressure drop and gravitational pressure drop in the well bore but ignore accelerational pressure drop, and fluid inflow effects into the wellbore.

Alvestad et al (1994) developed an interactive system denoted as NextWell, for modeling of multiphase inflow performance of long, highly deviated and horizontal wells. The reservoir pressure and multiphase flow distribution is modeled using a finite element method combined with automatic local grid refinement. A comprehensive multiphase wellbore flow model is available for accurate flow modeling of in the wellbore.

Penmatcha (1997) developed a one-dimensional reservoir/wellbore coupling model to calculate productivity of a horizontal well. The authors report that the ratio of wellbore pressure drop to reservoir drawdown gives good indication of frictional effects on well productivity. Penmatcha also show that error in productivity calculations from ignoring well-bore friction increases with larger reservoir permeabilities, high flow rates, or larger wellbore roughness and decreases with higher fluid viscosities or higher drawdowns. Penmatcha developed a comprehensive, transient, semi-analytical models to calculate the productivity of a finite conductivity and an infinite conductivity horizontal well. The finite-conductivity well model provides a reference solution to calculate the productivity of a horizontal well placed in a box shaped drainage volume with due consideration to frictional and accelerational pressure drops, fluid inflow effects and variable skin along the well. Penmatcha also developed a three-dimensional well model using the infinite and finite conductivity semi-analytical models.

Quyang (1998) developed wall friction factor correlations for pipe flow with influx. The correlations can be applied to determine wall friction shear and thus frictional pressure drop for either wall inflow or outflow and for either laminar axial flow or turbulent axial flow. The authors developed single phase wellbore flow model, which incorporates influence of wall inflow and outflow along with frictional and accelerational pressure drops. Their wellbore flow models provided excellent predictions of wellbore pressure drops in comparison with experimental data. His wellbore models can be incorporated in reservoir simulators or can be used as analytical reservoir inflow models.

Potnis (1998) studied the productivity of a horizontal, multilateral and designer well configurations and recommended a strategy for selection of optimal wellbore configuration for reservoir development.

To study the productivity of horizontal wells completed with slotted liners or perforations, Yula et al (2000) presented a semi-analytical model that couples the flow equations in the reservoir and wellbore. Their model takes into account the 3D convergence of flow around perforations and slots. The wellbore flow model considers pressure losses inside the horizontal section and the effect of axial influx of perforations and slots. The model also incorporates the effects of selective completion and non uniform skin distribution.

Wattenbarger et al (1998) presented a simple model to calculate the productivity of a horizontal well producing at constant flowing bottom hole pressure or constant rate from bounded reservoirs. Authors proposed correlations to calculate the shape factor and partial penetration skin for both cases. The correlations were developed using nonlinear regression of more than 800 numerical simulation runs for different reservoir aspect ratios, well locations, and well penetration ratios.

The survey of the literature shows very few researchers have studied the productivity of different well configurations over time. Our study is aimed at studying the productivity of conventional as well as unconventional well configurations with respect to time. We also study the impact of various factors such as anisotropy, well locations, partial completion on the well productivity for these configurations.

3. SIMULATION PROCEDURE AND WELL CONFIGURATIONS

This chapter presents the details of the simulation procedure and the description of the wellbore configurations considered for the study.

3.1 Simulation Model

The simulations were carried out using Eclipse 100, a fully implicit, three phase, black oil reservoir simulator, developed by Schlumberger (Schlumberger Reference Manual, 2000). We consider a 360 acres section model. The vertical payzone is 100 ft.

Table 3.1 Reservoir Data (Input to the Simultor)

Reservoir Depth	8800 ft.
Original Reservoir Pressure	4390 psia
Saturation Pressure	4390 psia
Oil Gravity	28° API
Reservoir Temperature	200° F
Gross- Pay	350-630 ft.
Net -Pay	Upto 444 ft.
Porosity	22%
Permeability	265 md
Original GOR	1678 SCF/STB
Original FVF	1.4 RB/STB
Initial Water Saturation	20.77%
Oil Viscosity	0.81 cp
Grid Dimensions	40X40X10
ΔX	99 ft
ΔY	99 ft
ΔZ	10 ft

The PVT, saturation and other reservoir data are taken from the description of Prudhoe Bay Section presented by Sharma (1994). For this study, the simulations were run with a maximum rate of 5000 STB/D and a minimum bottomhole pressure of 4200 psi. The wells are produced for a period of 10 years and the economic limit is 100 STB/D of oil. For the base case we consider vertical permeability equal to 26.5 md.

3.2 Well Configurations

The different types of wellbore configurations studied for this reservoir are briefly described below:

1. Horizontal Wells
2. Snake Wells (4 Segments and 8 Segments)
3. Fishbone Configuration

3.2.1 Horizontal Wells

a. HorizontalWell:

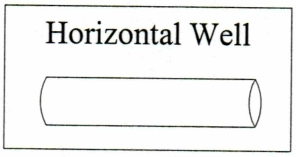

Figure 3.1: Schematic of Horizontal Well.

The horizontal well is located at the center of the reservoir both areally as well as vertically. The well runs parallel to X permeability direction. The complete horizontal section is open to flow. The radius of the well is 0.5 ft and the mechanical skin damage is 0.

b. Duallateral Configuration:

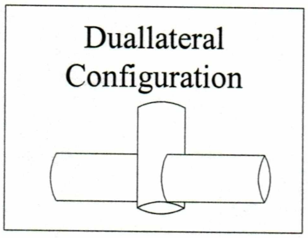

Figure 3.2: Schematic of Duallateral Well.

This configuration is essentially similar to the horizontal well configuration except that the vertical section is located at the center of the reservoir with two equal length laterals emanating from either sides of the vertical section. The length of each lateral is equal to half the length of the horizontal well described earlier. The laterals run parallel to the X permeability direction. The entire section is open to flow. The radius of the well laterals is 0.5 ft and there is no mechanical skin damage.

c. Mulitlateral Configuration:

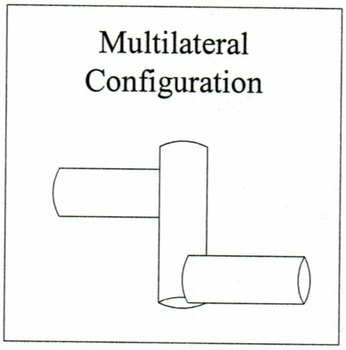

Figure3.3: Schematic of Multilateral Well.

This Configuration is similar to that of a duallateral configuration. The horizontal laterals are completed at different intervals. The laterals are equal length and and run parallel to X permeability direction.

3.2.2 Snake Wells (4 segments and 8 segments)

a. Snake Well (4 Segments):

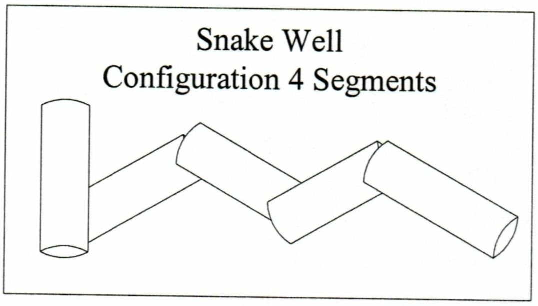

Figure 3.4: Schematic of Snake Well (4 segments).

In this configuration the horizontal section consists of undulations in vertical direction. The number of X direction grid blocks in which the well is completed is equal to that of the horizontal well. The well is completed in 3 different intervals. There are 4 segments of equal length. All the sections are open to flow.

b. Duallateral Snake Well Configuration (4 Segments):

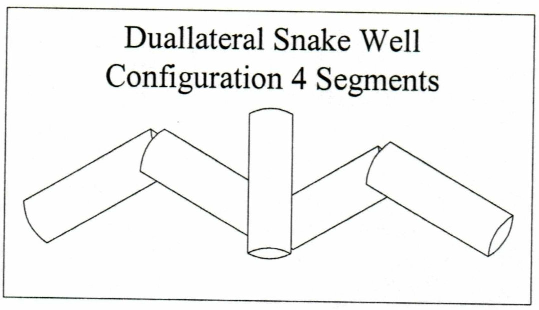

Figure 3.5: Schematic of Duallateral Snake Well (4 Segments).

This configuration is similar to that of snake well configuration. The vertical section is situated at the center of the reservoir and the 2 undulated segments are drilled on both the sides of the vertical section. The entire section of the well is open to flow. The number of X direction gridblocks in which the well is completed is equal to that of duallateral well.

c. Multilateral Snake Well Configuration (4 Segments)

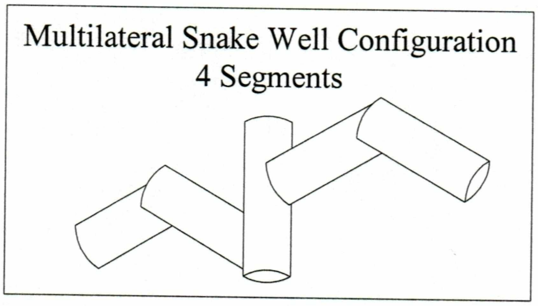

Figure 3.6: Schematic of Mulitlateral Snake Well (4 Segments).

In this configuration the lateral snake segments are completed at different intervals of the reservoir. The number of X direction gridblocks in which the segments of the well are completed are equal to that multilateral well.

d. Snake Well (8 Segments):

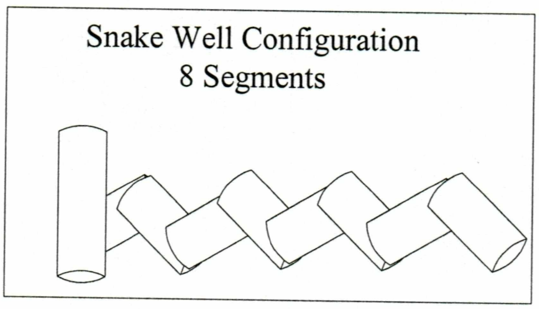

Figure 3.7: Schematic of Snake Well (8 Segments).

This configuration is similar to that of snake well with 4 segments. There are 8 segments in the horizontal section instead of 4. The number of X direction gridblocks in which the well is completed is equal to that of the horizontal well. The Z layers penetrated by this configuration is equal to that penetrated by snake well with 4 segments.

e. Duallateral Snake Well Configuration (8 Segments)

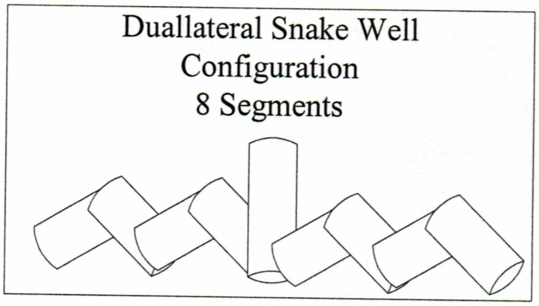

Figure 3.8: Schematic of Duallateral Snake Well (8 Segments).

This configuration is similar to duallateral snake well with 4 segments. There are 4 segments of horizontal sections on both sides of the vertical section (Fig 3.8). The segments are completed in the same X and Z gridblocks as that of the well with 4 segments. The radius of the well is 0.5 ft and there is no mechanical skin damage.

f. Multilateral Snake Well Configuration (8 Segments)

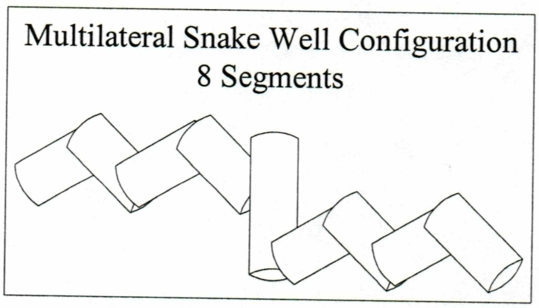

Figure 3.9: Schematic of Multilateral Snake Well (8 Segments).

This configuration is similar to the 4-segment Multilateral Snake Well configuration but with 8 segments.

3.2.3 Fish Bone Configuration

a. Fishbone Configuration

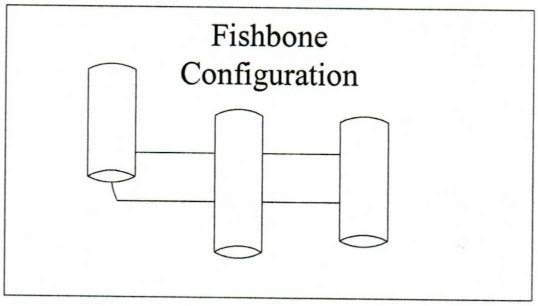

Figure 3.10: Schematic of Fishbone Configuration.

The fish bone configuration consists a horizontal mother hole with two nodes along the length. Each node has laterals drilled normal to the mother hole in the horizontal plane. The total equivalent length of the drilled section is equal to that of the horizontal well. The entire length of the mother hole and the laterals is open to flow.

b. Duallateral Fishbone Configuration

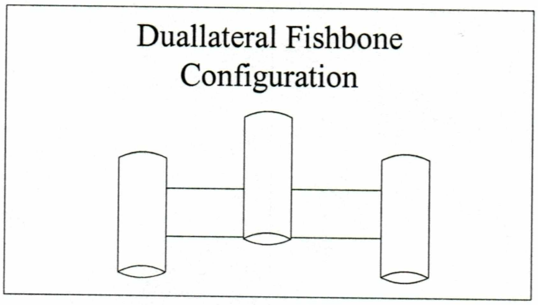

Figure 3.11: Schematic of Duallateral Fishbone Configuration.

This configuration consists of two lateral horizontal motherholes on either sides of the vertical section. Each motherhole has a lateral running parallel to Y permeability direction. The total equivalent length of the drilled section is equal to that of the duallateral well configuration. The entire length of mother hole and the laterals is open to flow. Both the mother holes and laterals are in the same horizontal plane.

c. Multilateral Fishbone Configuration

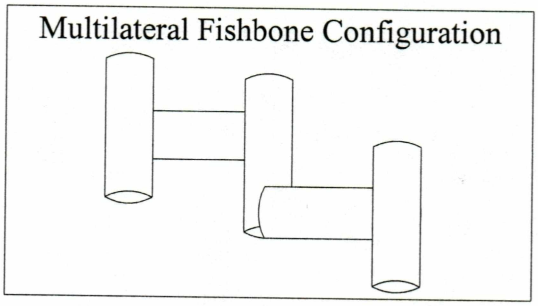

Figure 3.12: Schematic of Multilateral Fishbone Configuration.

This configuration is similar to that of duallateral lateral fishbone configuration, except that the two mother holes are drilled at different intervals. The entire section of the mother holes and the laterals is open to flow.

4. RESULTS AND DISCUSSION

In this chapter, results obtained from the simulation studies for different configurations are presented. The Influence of vertical position, permeability anisotropy, partial completion and pressure drop on performance of different well configurations is discussed. Comparison of results from numerical simulation versus those from analytical models is also reported.

4.1 Model Validation

Eclipse 100 does not calculate productivity index for horizontal wells explicitly. PI was calculated using the following formula:

$$J = \frac{q}{P_d - P_w} \tag{4.1}$$

Where

q = flowrate.

P_d = average reservoir pressure

P_w = wellbore pressure

For this study the productivity index for each configuration has been calculated using the above formula and the average reservoir pressure at each time step. Using the data presented earlier in Table 3.1, we calculated the steady state and pseudo state PIs from analytical models. Horizontal well of length 2079 ft. and vertical permeability of 26.5 md were considered. Table 4.1 shows the results from analytical models.

Table 4.1 Comparison of calculated and simulated values of productivity index

Formula	Productivity Index (STB/D/PSI)	Remarks
Steady State		
Joshi	93.08	(Eq.1 Appendix Table A1)
Renard & Dupuy	96.23	(Eq.2 Appendix Table A1)
Borisov (Potnis 98)	96.32	(Eq.3 Appendix Table A1)
Pseudosteady State		
Babu & Odeh	83.31	(Eq.4 Appendix Table A1)
Wattenbarger	86.43	(Eq.5 Appendix Table A1)
Economides	57.84	(Eq.6 Appendix Table A1)
Eclipse 100 (Simulator)	50.19	

4.2 Influence of Vertical Position

This section presents the discussion of results obtained from the simulation of placement of wells at different vertical positions. The wellbore configurations reported in section 3.2 are considered. Three vertical position cases are considered, Zw/h of 0.2,0.5,0.8 with 0.5 as the base case. Fig 4.1 shows the schematic of a horizontal well configuration of diameter d, placed in a payzone of thickness h, at a distance of Zw from top of the payzone.

4.2.1 Performance of Horizontal Wells

In this section performance of horizontal well, duallateral well and multilateral well is discussed.

Fig. 4.2 and 4.3 show the productivity and cumulative oil recovery of horizontal well configuration. It is seen that as Zw/h increases from 0.2 to 0.8 the well productivity decreases. This decrease in production can be attributed to the pressure gradient. The well drilled at higher vertical position (low Zw/h) will have a lower pressure potential and therefore will contribute higher production.

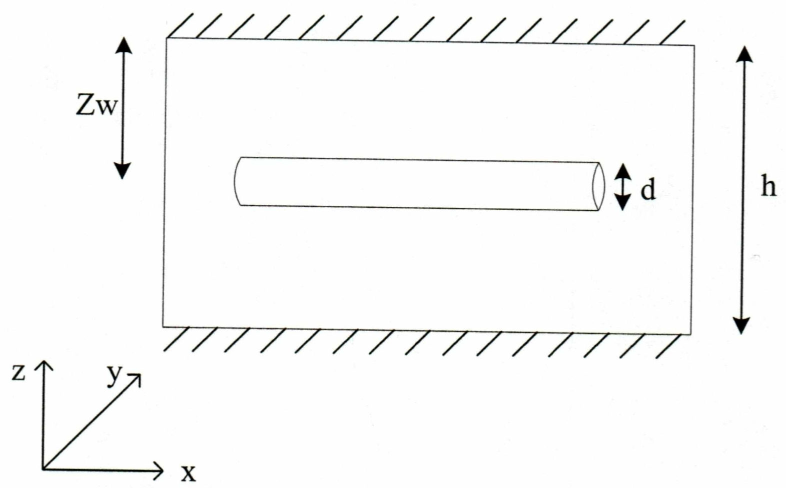

Figure 4.1: Schematic of Horizontal Well

Fig. 4.4 and 4.5 show the production performance and cumulative production from a duallateral well configuration. It shows a decreasing productivity trend with increasing Zw/h ratio. The production performance of duallateral well is similar to that of horizontal well configuration as seen in previous section. Due to absence of lateral heterogeneity, there is no significant difference between the performance of duallateral configuration and horizontal well configuration. From Fig. 4.4 it is seen that the cumulative production from the well completed at Zw/h = 0.2 and 0.5 is equal although their initial productivity indices are different (Fig. 4.3).

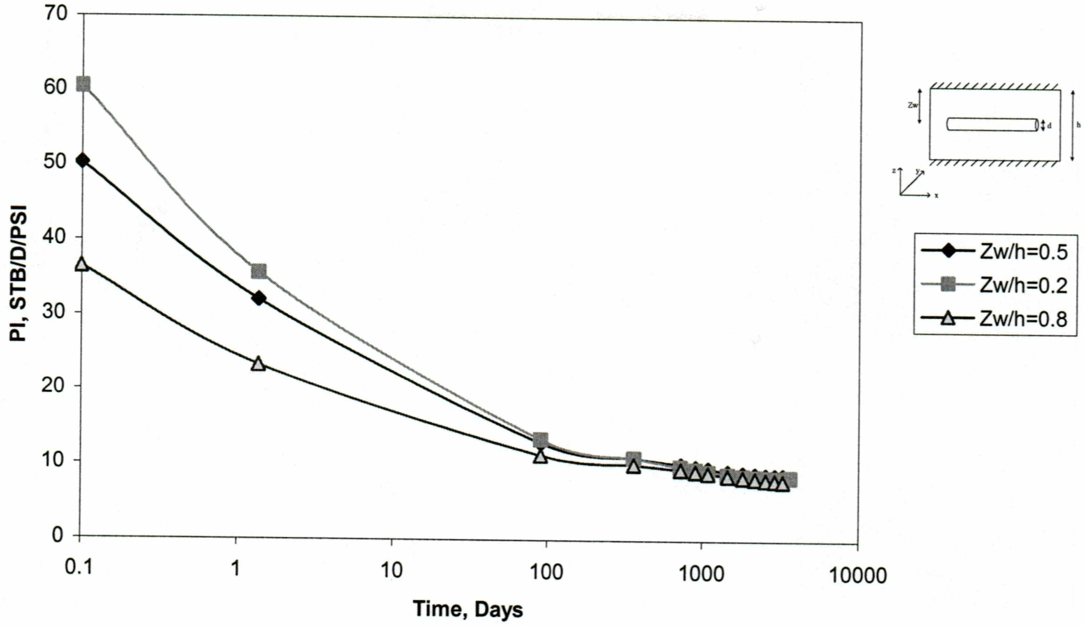

Figure 4.2: PI Vs Time, Horizontal Well Configuration, Influence of vertical position.

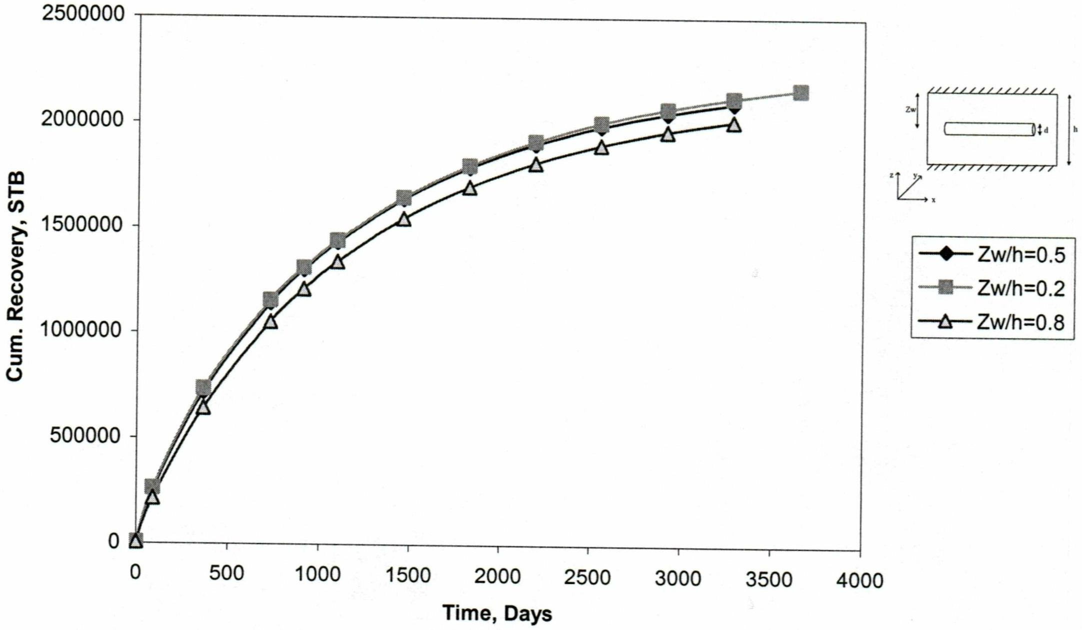

Figure 4.3: Cumulative Recovery Vs Time, Horizontal Well Configuration, Influence of vertical position.

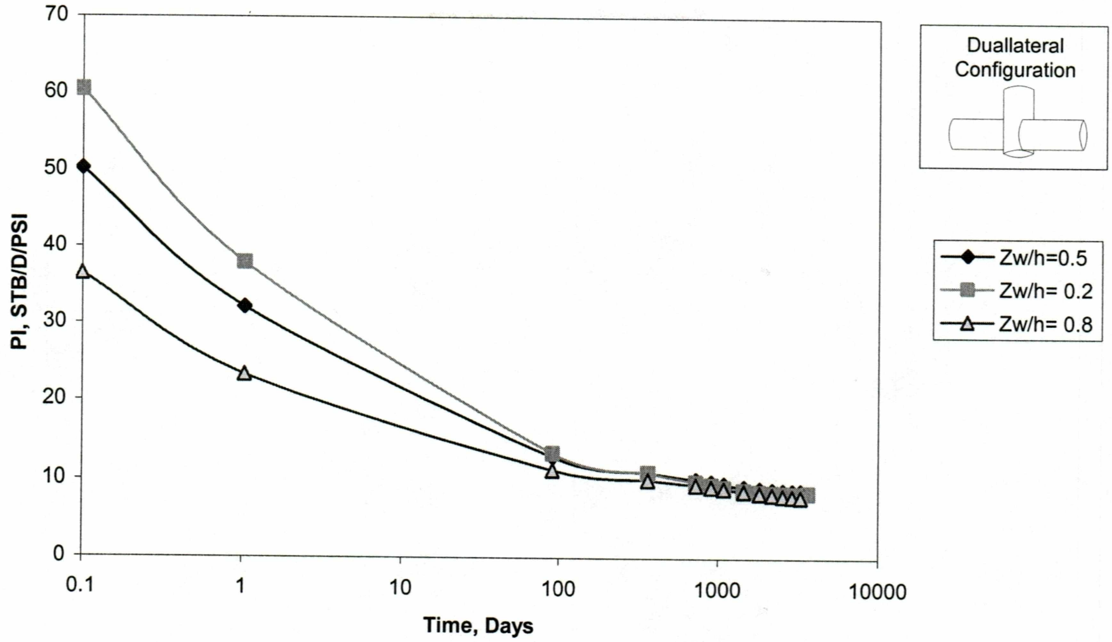

Figure 4.4: PI Vs Time, Duallateral Well Configuration, Influence of vertical position.

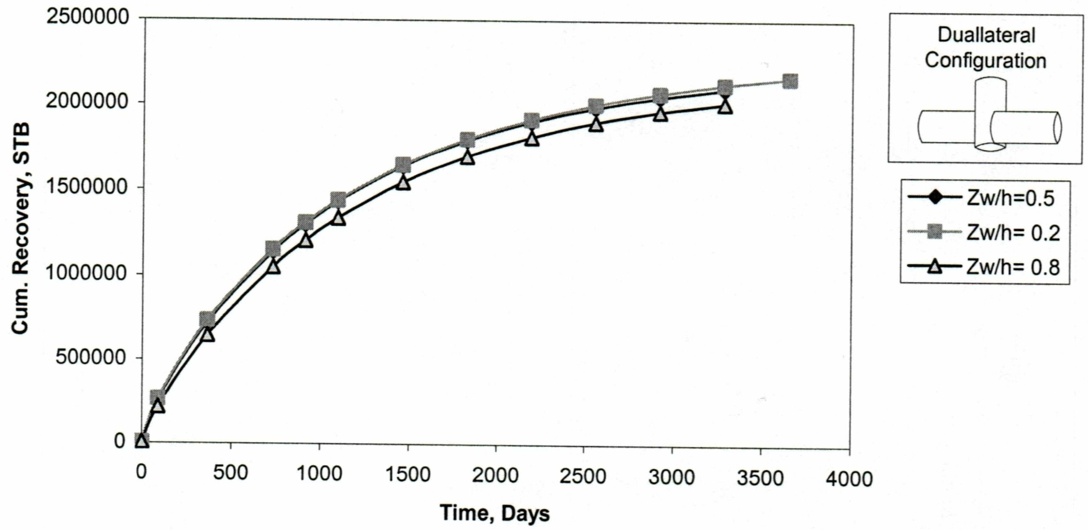

Figure. 4.5: Cumulative Recovery Vs Time Duallateral Well Configuration, Influence of vertical position.

From Fig. 4.6 it is seen that the productivity index of multilateral well configuration shows almost same trend as that of horizontal well configuration (Fig 4.1). The position of the laterals does not significantly impact the performance of this configuration. The productivity decreases with increase in Zw/h ratio. From Fig. 4.7 it is seen that the cumulative production for Zw/h = 0.2 and 0.5 is equal.

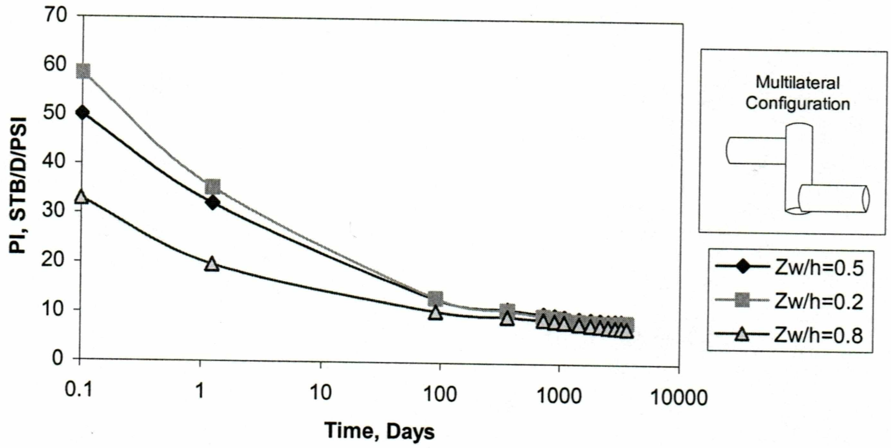

Figure 4.6: PI Vs Time, Multilateral Well Configuration Influence of vertical position.

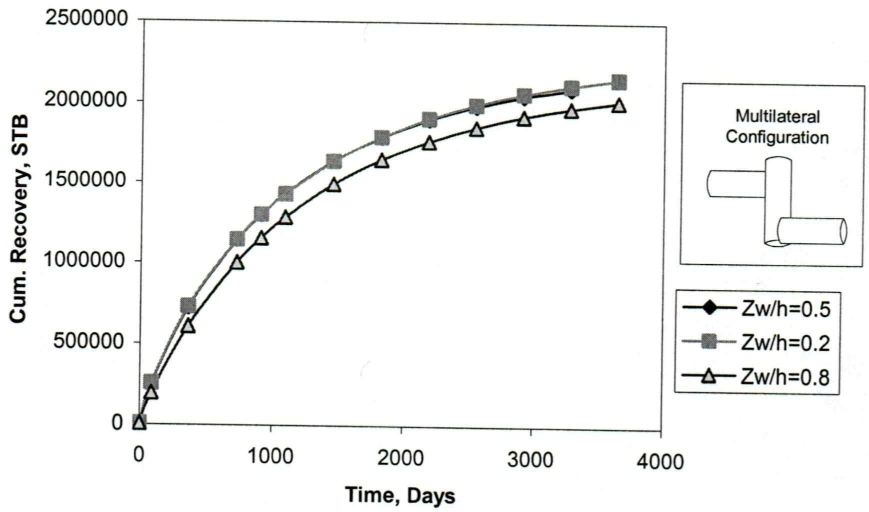

Figure 4.7: Cumulative Recovery Vs Time, Multilateral Well Configuration Influence of vertical position.

4.2.2 Performance of Snake Wells (4 Segments and 8 Segments)

From fig 4.8 and 4.9 it is seen that for a 4 segmented snake well, the PI of well placed at 0.2 position is higher than that of 0.5 position at 0.1 days but becomes equal after 1 day. The cumulative production for 0.2 and 0.5 is also equal. The advantage of snake well over horizontal well is increased reservoir contact by penetration in different intervals. Although this configuration has an effective producing length slightly longer than that of horizontal well considered earlier, it is seen that it does not significantly increase the cumulative production as compared to that of horizontal well (Fig 4.3). This again can be attributed to lack of reservoir heterogeneity.

Fig. 4.10 shows that productivity index of a duallateral snake well configuration with 4 segments, completed at 0.2 and 0.5 position is equal after 1 days of production. There is a significant difference between productivity index for well completed at 0.5 position and 0.8 position. This difference is noticeable from the cumulative production depicted in Fig.4.11.

Fig. 4.12 and 4.13 show productivity index and cumulative production for a multilateral snake well configuration with 4 segments. It is seen that at 1 day the productivity index of the well completed at 0.2 position is slightly higher than that of the well completed at 0.5 position, however the cumulative production is the same for both these cases.

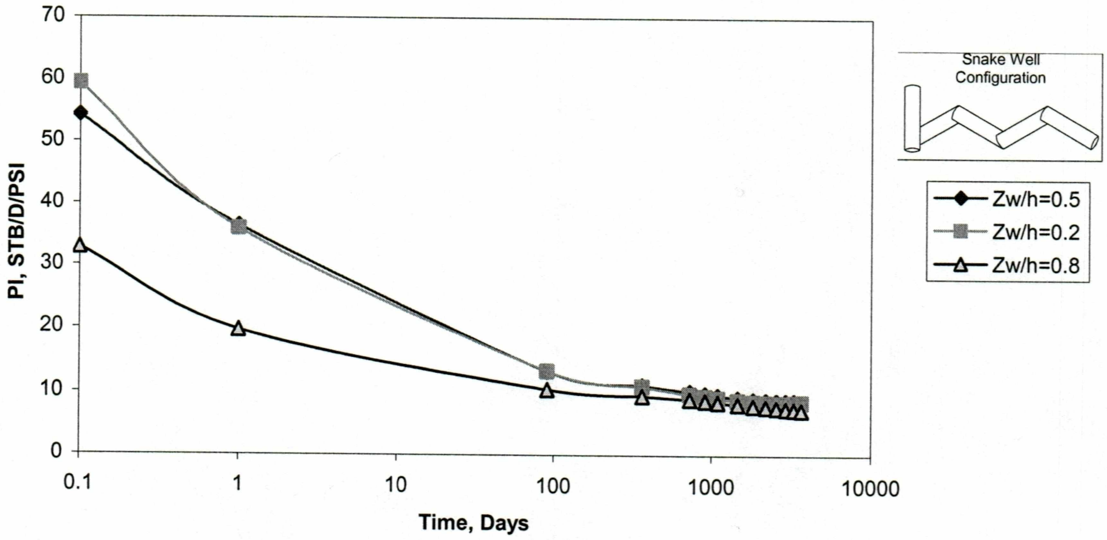

Figure 4.8: PI Vs Time, Snake Well Configuration 4 Segments Influence of vertical position.

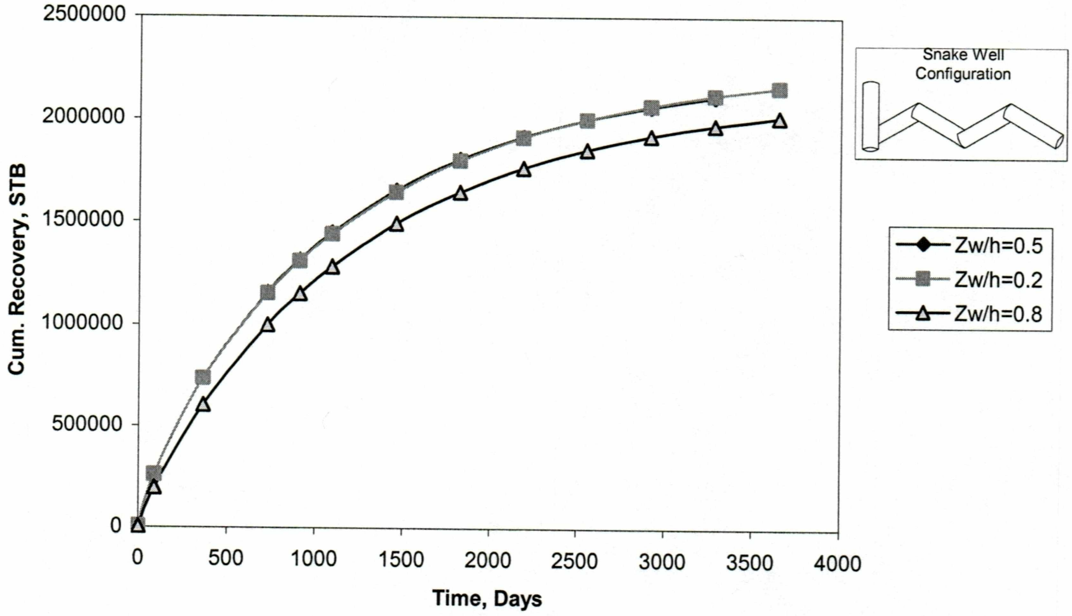

Figure 4.9: Cumulative Recovery Vs Time, Snake Well Configuration 4 Segments, Influence of vertical position.

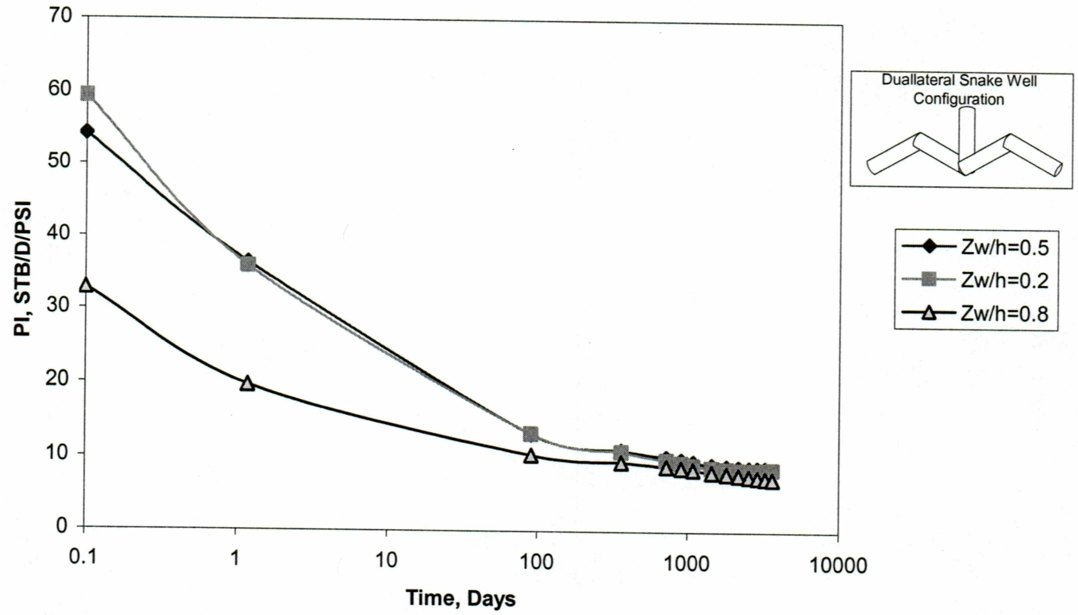

Figure 4.10: PI Vs Time Duallateral, Snake Well Configuration 4 Segments, Influence of vertical position.

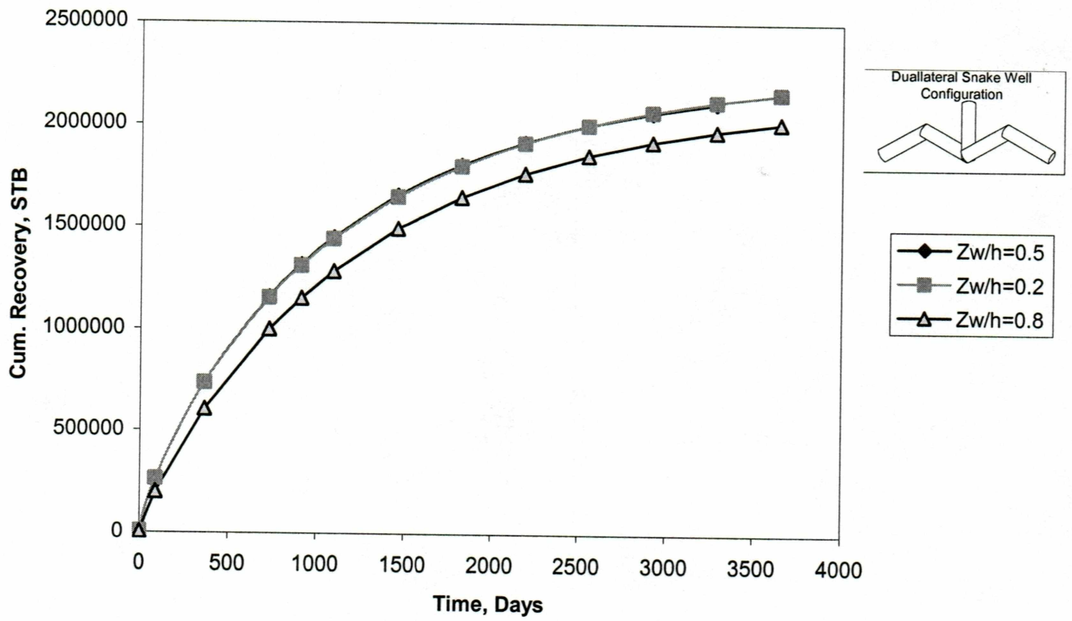

Figure 4.11: Cumulative Recovery Vs Time Duallateral Snake Well Configuration 4 Segments, Influence of vertical position.

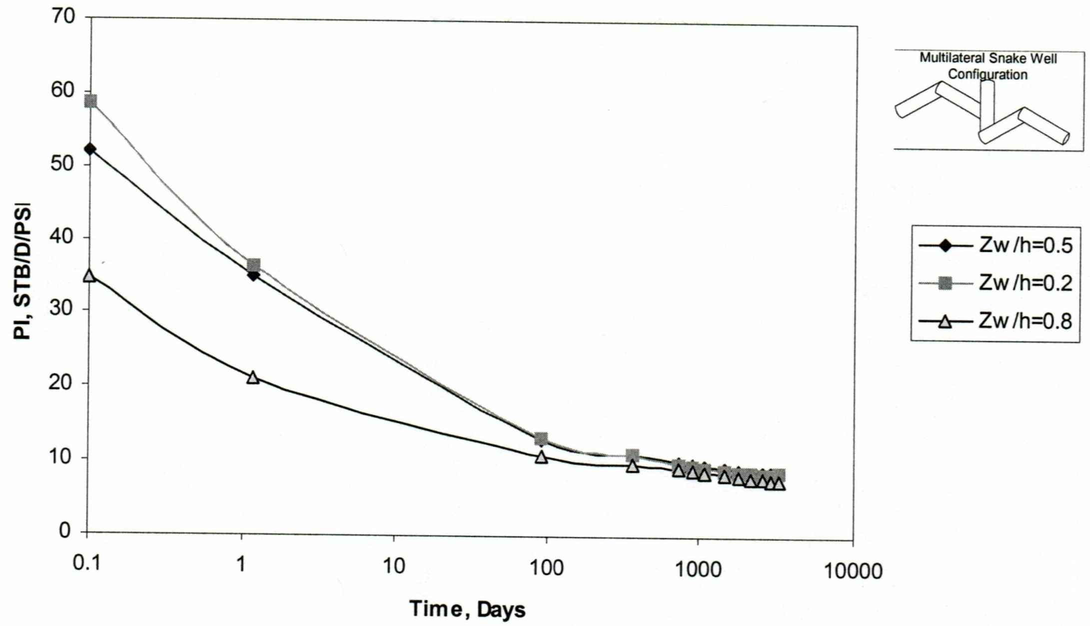

Figure 4.12: PI Vs Time Multilateral Snake Well Configuration 4 Segments, Influence of vertical position.

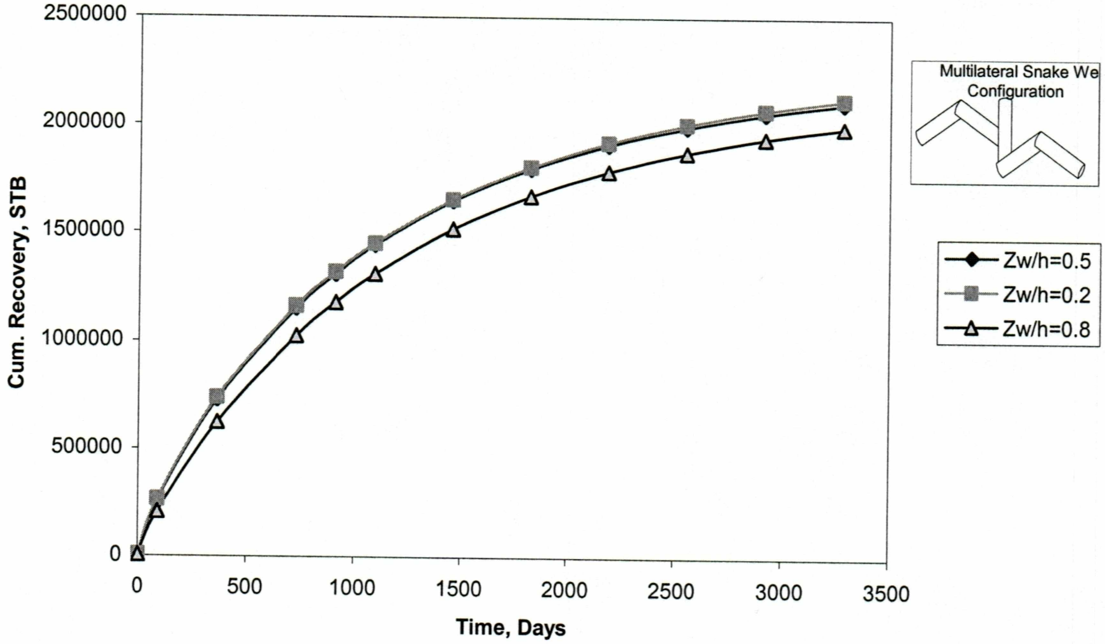

Figure 4.13: Cumulative Recovery Vs Time Multilateral Snake Well Configuration 4 Segments, Influence of vertical position.

Fig. 4.14 and 4.15 shows comparison of productivity index and cumulative production for an 8 segmented snake well completed at Zw/h=0.2, 0.5 and 0.8. The advantage of an 8- segment well over a 4-segment well is increased reservoir contact. The main disadvantage would be increased pressure losses due to more tortuosity in the 8-segment wellbore. Fig 4.14 shows that at 1 day the productivity of the well completed at Zw/h= 0.2 position is slightly lower than that completed at 0.5 position. There is a significant difference between the productivity index and the cumulative production for wells completed at 0.5 and 0.8 (Fig. 4.15).

Fig 4.16 and 4.17 depict the performance of duallateral snake well configuration with 8 segments. It is seen that the cumulative production for wells completed at Zw/h=0.2 and 0.5 position is equal, but higher than the production form a well completed at 0.8 interval.

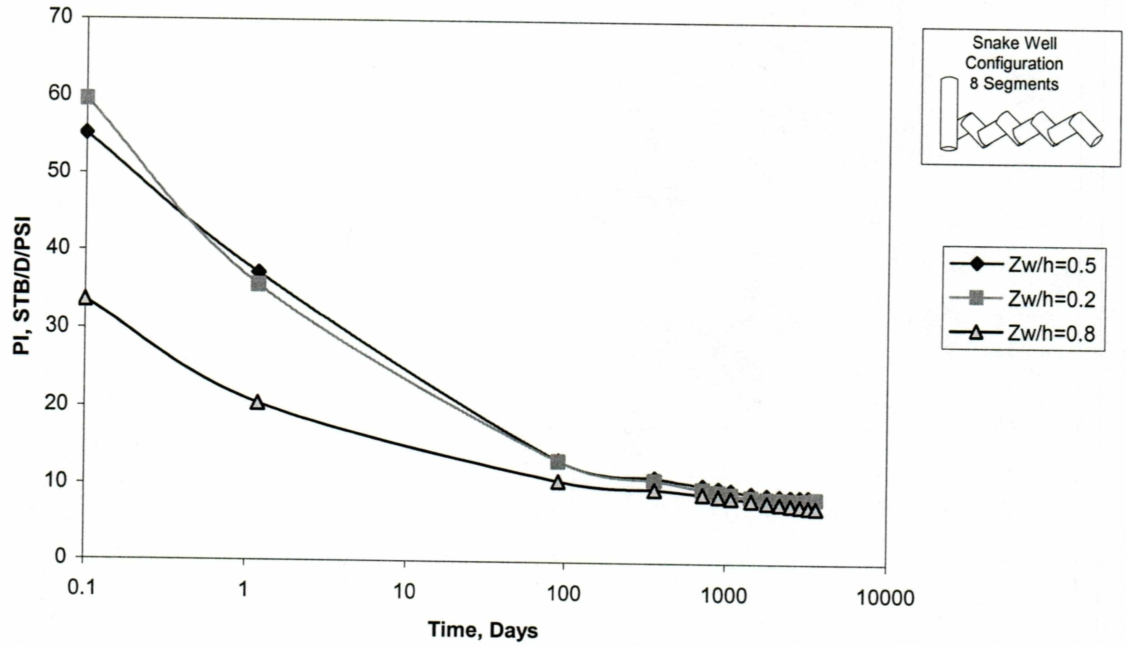

Figure 4.14 : PI Vs Time, Snake Well Configuration 8 Segments, Influence of vertical position.

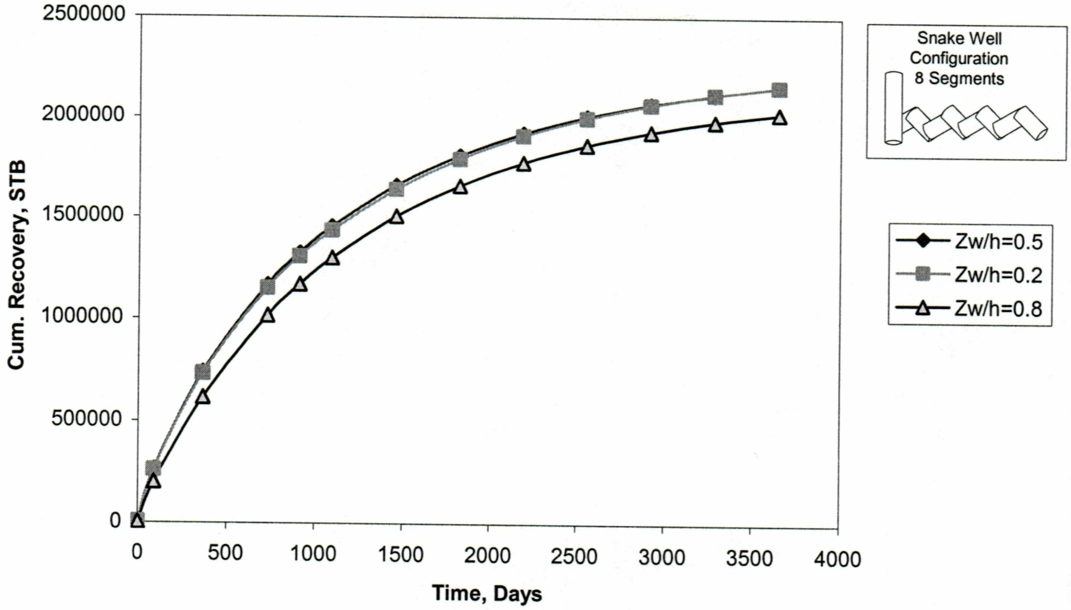

Figure 4.15: Cumulative Recovery Vs Time Snake Well Configuration 8 Segments, Influence of vertical position.

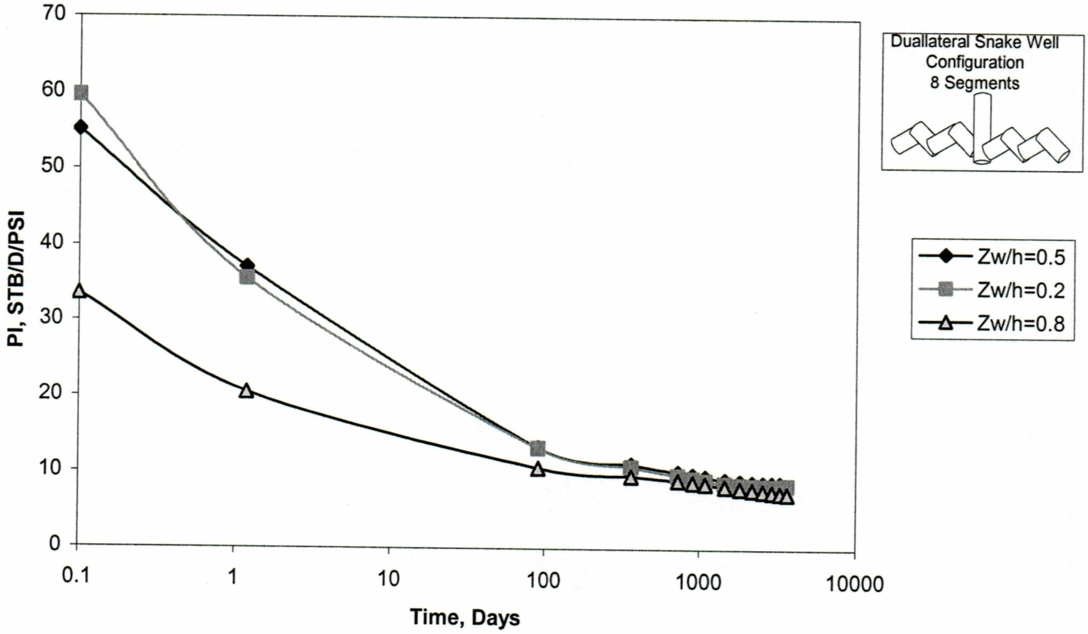

Figure 4.16: PI Vs Time Duallateral Snake Well Configuration 8 Segments, Influence of vertical position.

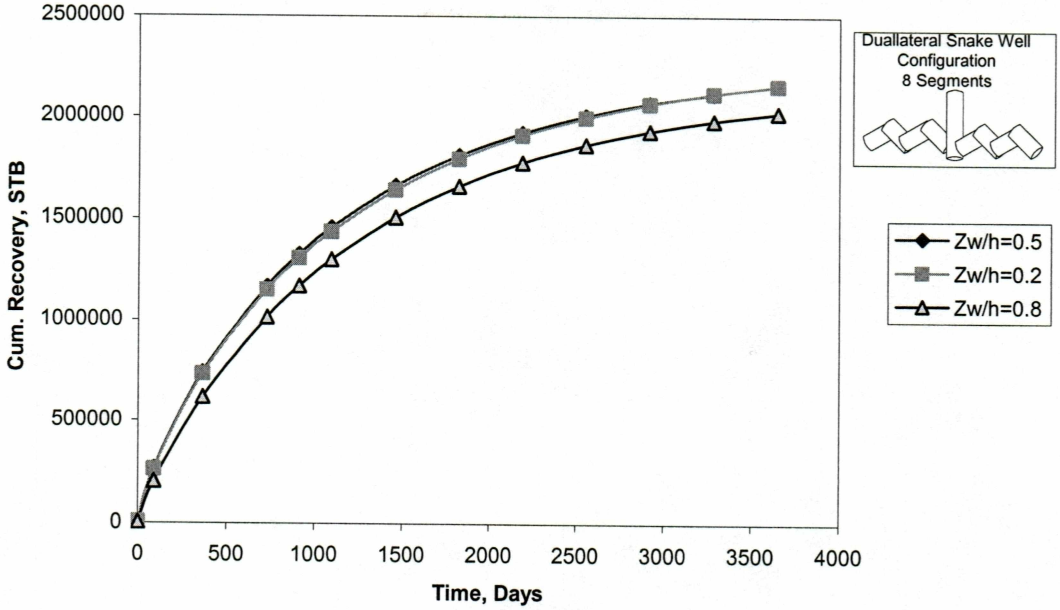

Figure 4.17: Cumulative Recovery Vs Time Duallateral Snake 8 Segments, Influence of vertical position.

For a multilateral well with 8 segments, shown in Fig. 4.18 and 4.19, the productivity index at 1 day for wells completed at Zw/h=0.2 and 0.5 position is equal (Fig. 4.18) unlike duallateral snake well. The productivity index and cumulative production for the well completed at 0.8 position is significantly low as compared to the wells completed at 0.2 and 0.5 interval.

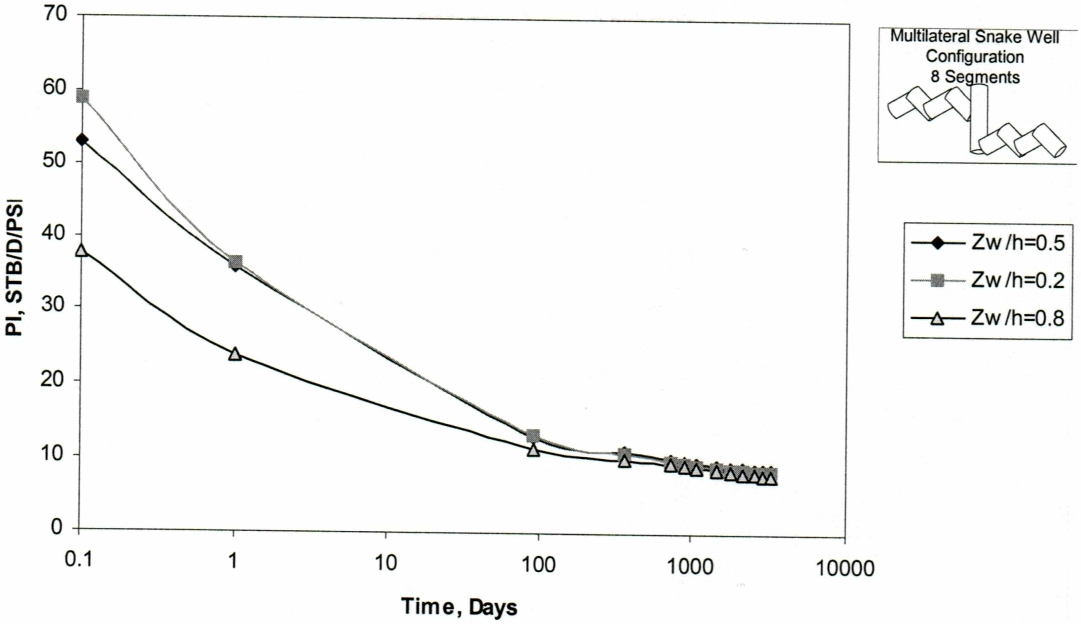

Figure 4.18: PI Vs Time, Multilateral Snake Well Configuration 8 Segments Influence of vertical position.

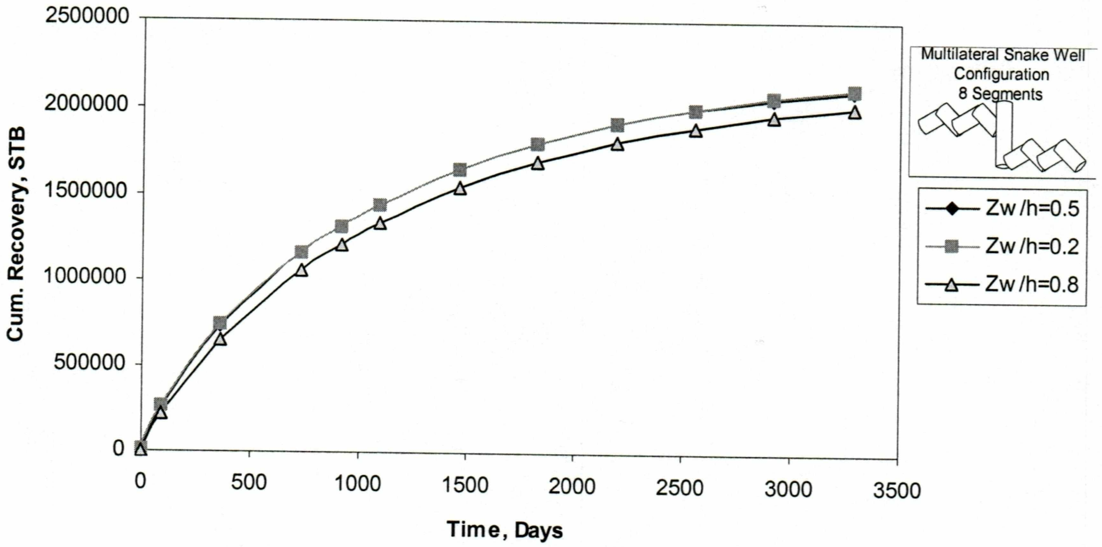

Figure 4.19: Cumulative Recovery Vs Time, Multilateral Snake Well Configuration 8 Segments, Influence of vertical position.

4.2.3 Performance of Fishbone Configuration

Unlike snake wells, fishbone configuration considered in this study penetrates the same layer. The effective producing length of this configuration is equal to the horizontal well considered previously. Figures 4.20 and 4.21 show the production performance and cumulative production for a 10 year period. The comparison of wells completed at Zw/h = 0.2, 0.5 and 0.8 shows that as Zw/h increases the productivity index decreases. However the cumulative production for Zw/h= 0.2 and 0.5 positions is equal and higher than that of 0.8. It is also observed that the productivity index and cumulative for this configuration are also lower than those of the horizontal well productivity index (Fig. 4.2) for Zw/h of 0.2 and 0.8 so also is the cumulative production.

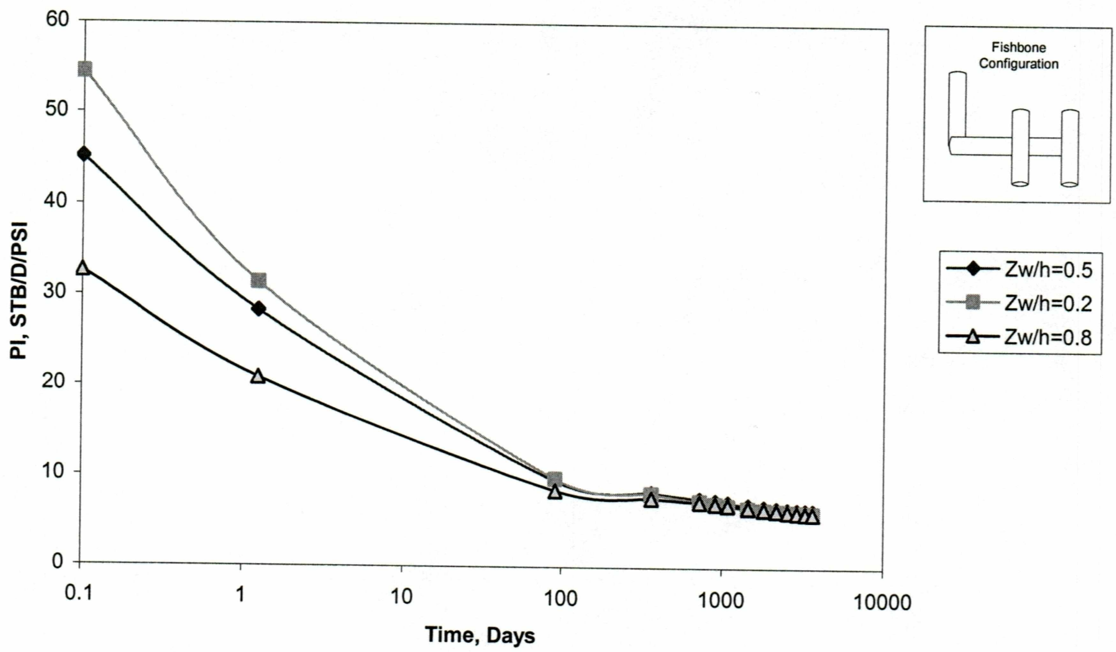

Figure 4.20: PI Vs Time, Fishbone Configuration, Influence of vertical position.

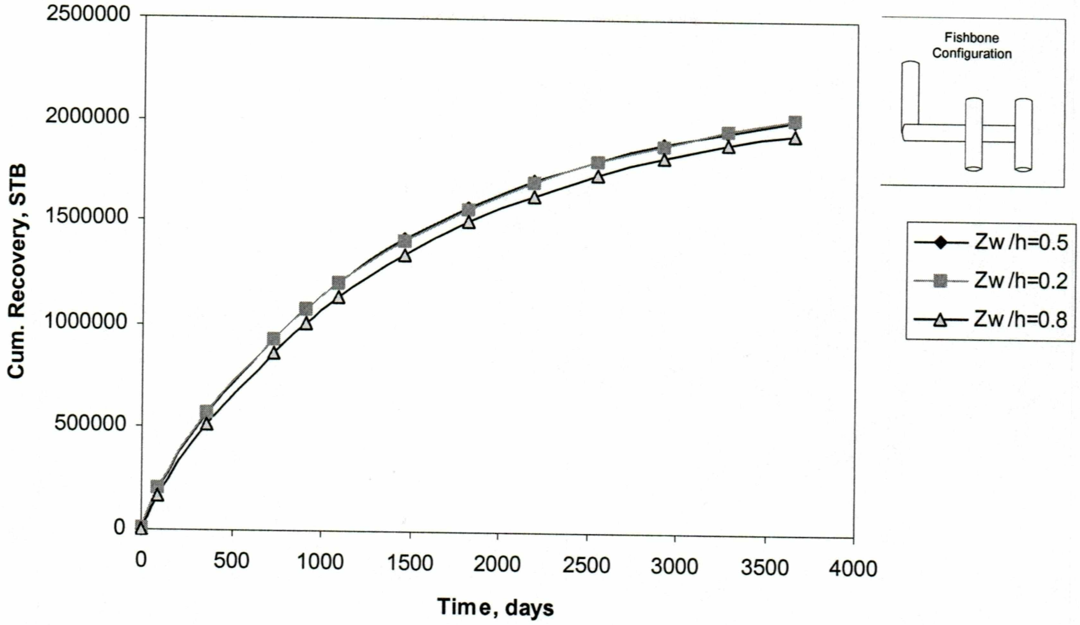

Figure 4.21: Cumulative Recovery Vs Time Fishbone Configuration, Influence of vertical position.

Figure 4.22 and 4.23 show the productivity index and cumulative production for a duallateral fish bone configuration. The initial productivity index decreases as the elevation ratio increases. The cumulative production is equal for Zw/h of 0.2 and 0.5.

For a multilateral fishbone configuration, the productivity index increases as Zw/h decreases, as seen from Fig. 4.24. However the cumulative production for Zw/h of 0.2 and 0.5 is equal (Fig. 4.25).

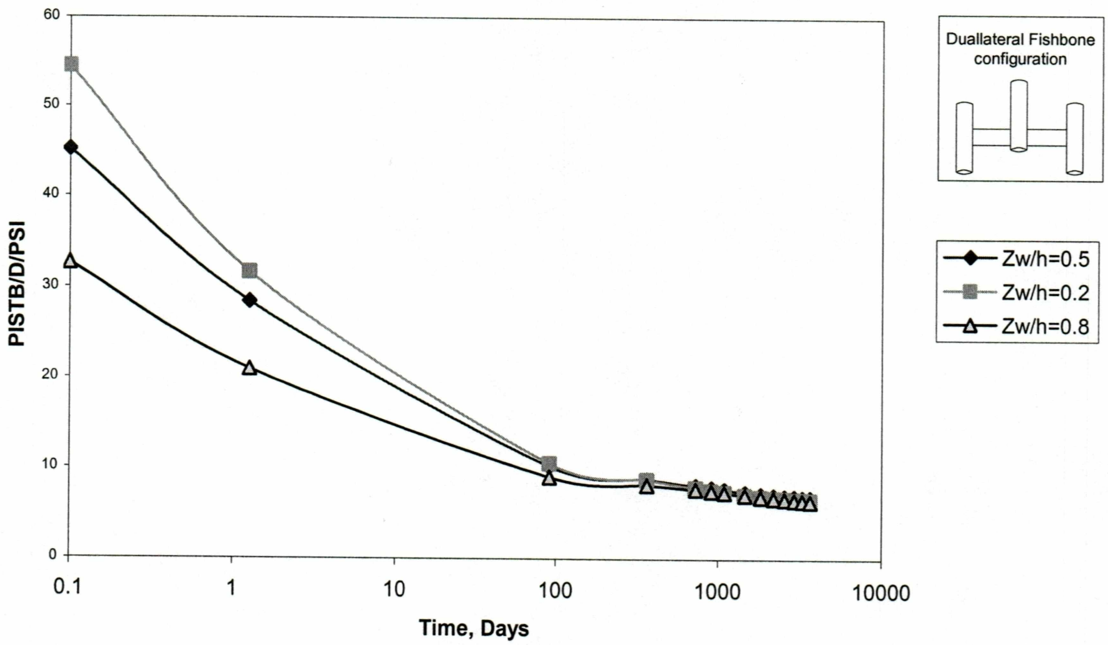

Figure 4.22: PI Vs Time, Duallateral Fishbone Configuration, Influence of vertical position.

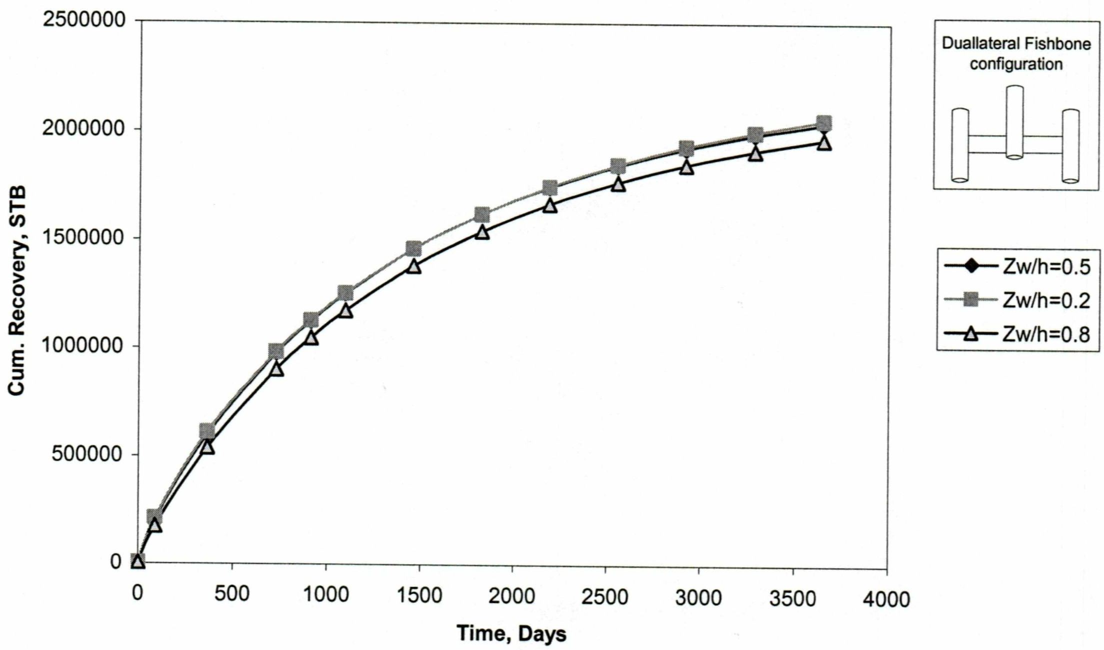

Figure 4.23: Cumulative Recovery Vs Time, Duallateral Fishbone Configuration, Influence of vertical position.

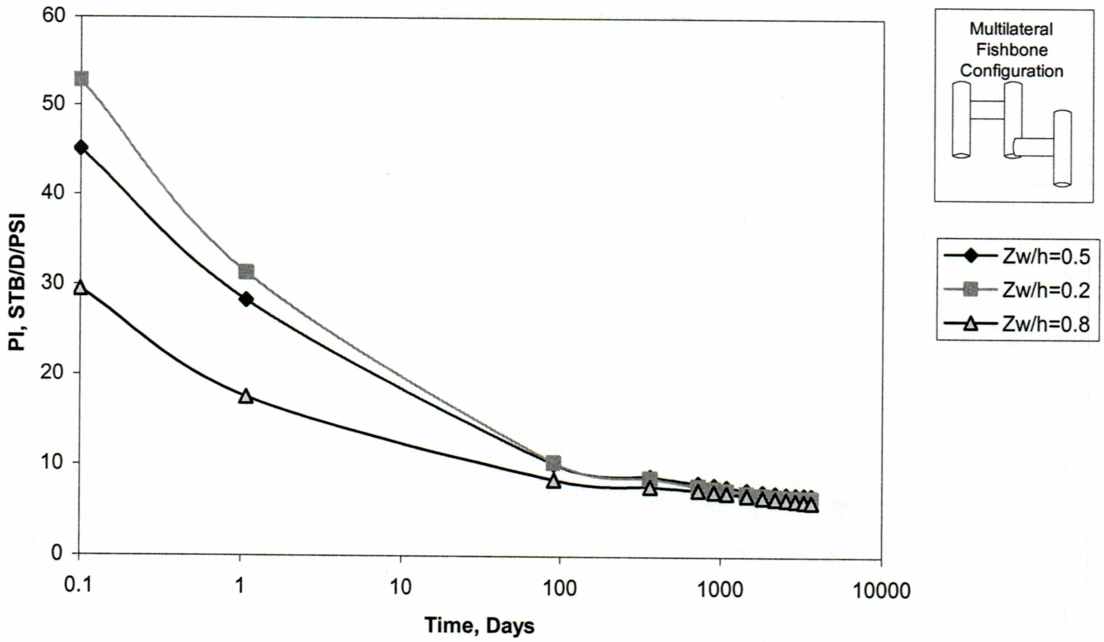

Figure 4.24: PI Vs Time, Multilateral Fishbone Configuration, Influence of vertical position.

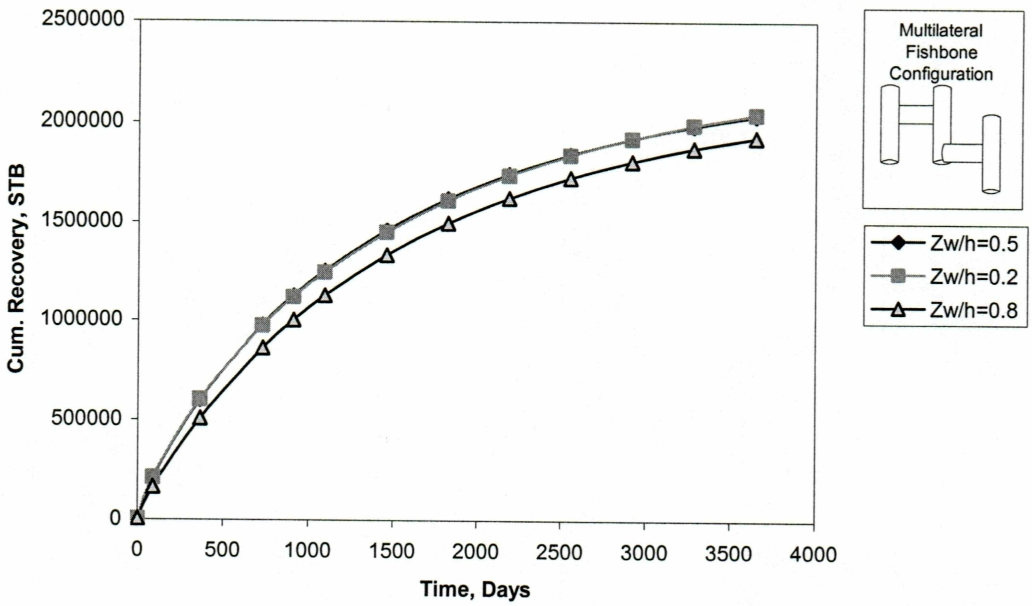

Figure 4.25: Cumulative Recovery Vs Time, Multilateral Fishbone Configuration, Influence of vertical position.

4.2.4 Remarks

1. As the Zw/h ratio increases from 0.2 to 0.8, the productivity for all the wellbore configurations decreases.
2. There is no significant different between the cumulative production of wells for Zw/h ratios of 0.2 and 0.5 and for most of the configurations it is equal.
3. All the configurations show an indentical performance due to lack of reservoir heterogeneity.

4.3 Influence of Permeability Anisotropy

The influence of permeability anisotropy (K_v/K_h) on well productivity of different configurations is discussed in this section. The K_v/K_h ratios of 1, 0.1, 0.01,0.001 and 0.0001 are considered.

4.3.1 Performance of Horizontal Wells

Fig. 4.26 and Fig. 4.27 show the productivity index and cumulative production for a horizontal well configuration. It is seen that as the permeability ratio decreases, the productivity index becomes constant.

From Fig. 4.28 and 4.29 it is seen that for a duallateral well configuration, the productivity index decreases with decrease in permeability ratio, the trend is similar to that of the horizontal well seen in the earlier section (Fig. 4.24).

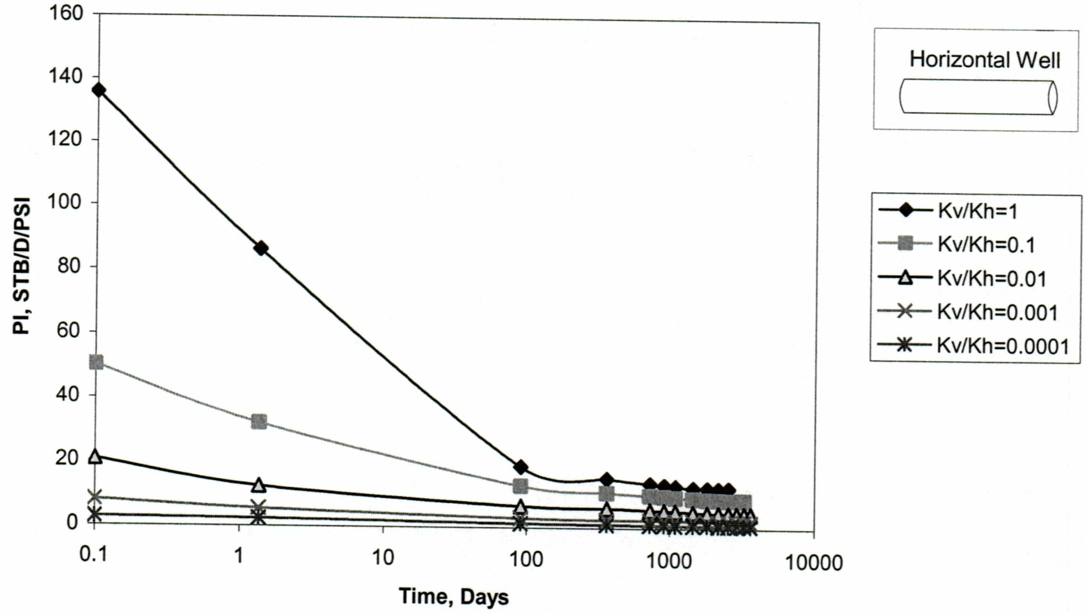

Figure 4.26: PI Vs Time, Horizontal Well Configuration, Influence of Permeability Anisotropy.

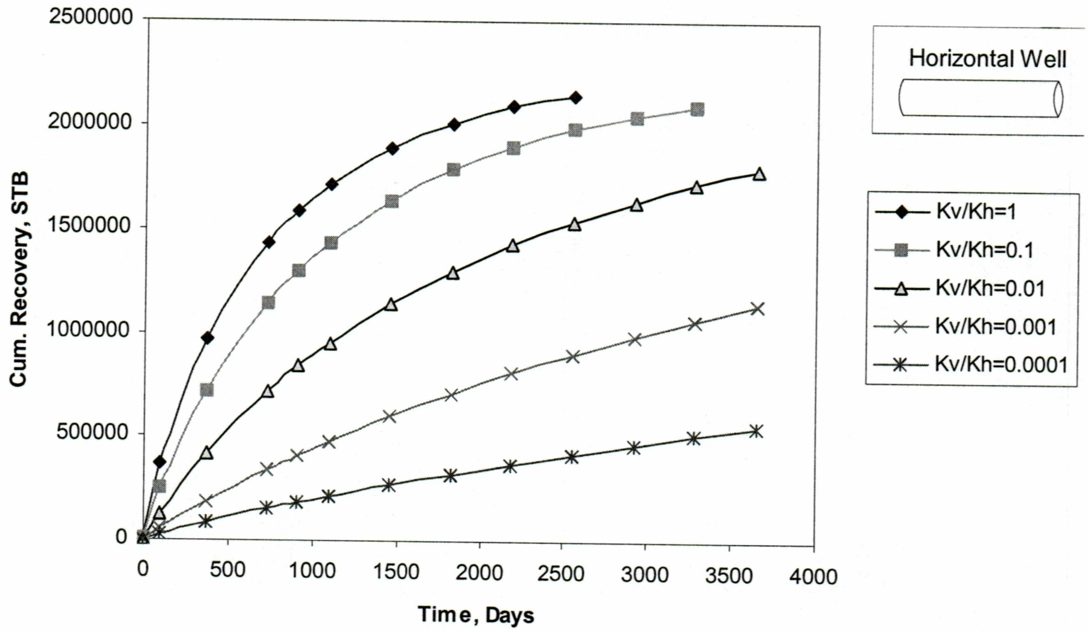

Figure 4.27: Cumulative Recovery Vs Time, Horizontal Well Configuration, Influence of Permeability Anisotropy.

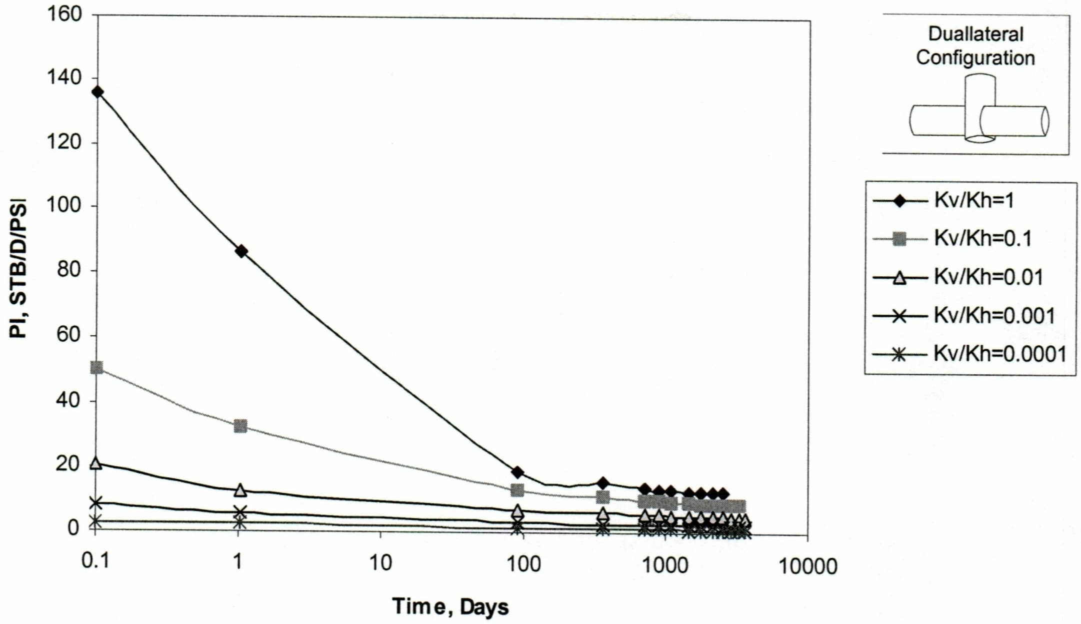

Figure 4.28: PI Vs Time, Duallateral Well Configuration, Influence of Permeability Anisotropy.

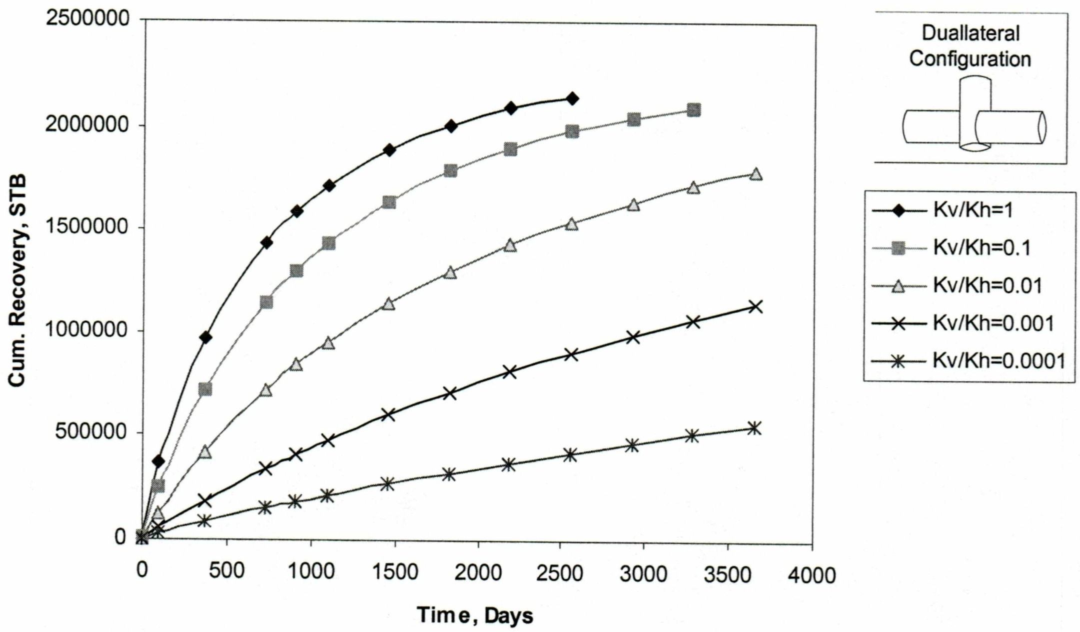

Figure 4.29: Cumulative Recovery Vs Time, Duallateral Well Configuration, Influence of Permeability Anisotropy.

For a multilateral configuration, the productivity index and the cumulative production goes on decreasing with decrease in permeability ratio as observed from Fig. 4.30 and 4.31.

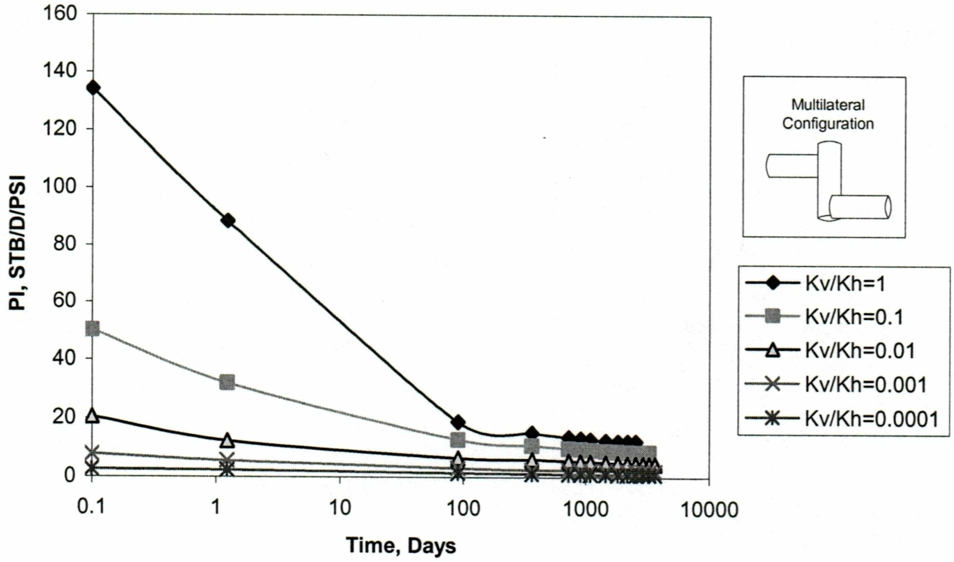

Figure 4.30: PI Vs Time, Multilateral Well Configuration, Influence of Permeability Anisotropy.

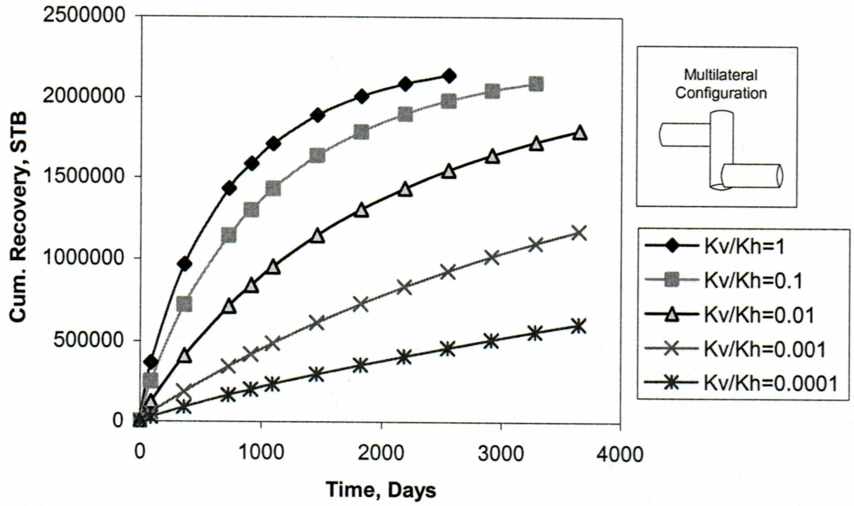

Figure 4.31: Cumulative Recovery Vs Time Multilateral Well Configuration Influence of Permeability Anisotropy.

4.3.2 Performance of Snake Wells (4 Segments and 8 Segments)

In this section we present the results obtained from the simulation of snake well configurations for varying permeability anisotropy ratios.

Fig. 4.32 shows the productivity index of snake well with 4 segments for K_v/K_h ratios from 0.0001 to 1. It is seen that as the permeability ratio decreases, the productivity index decreases. Also from Fig. 4.33 it is seen that as the anisotropy ratio decreases, the cumulative production decreases.

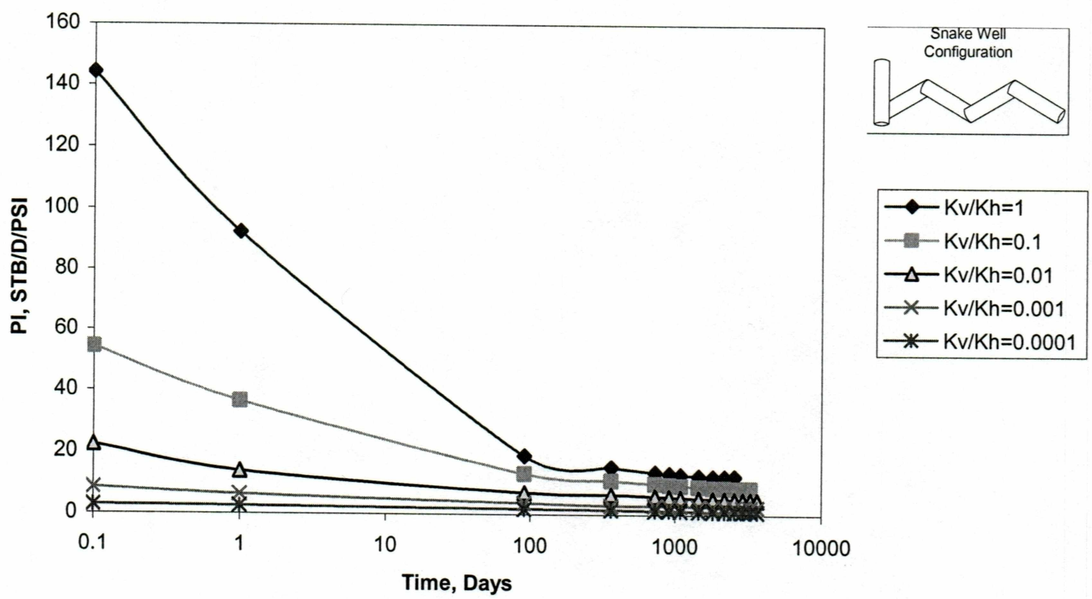

Figure 4.32: PI Vs Time, Snake Well Configuration 4 Segments, Influence of Permeability Anisotropy.

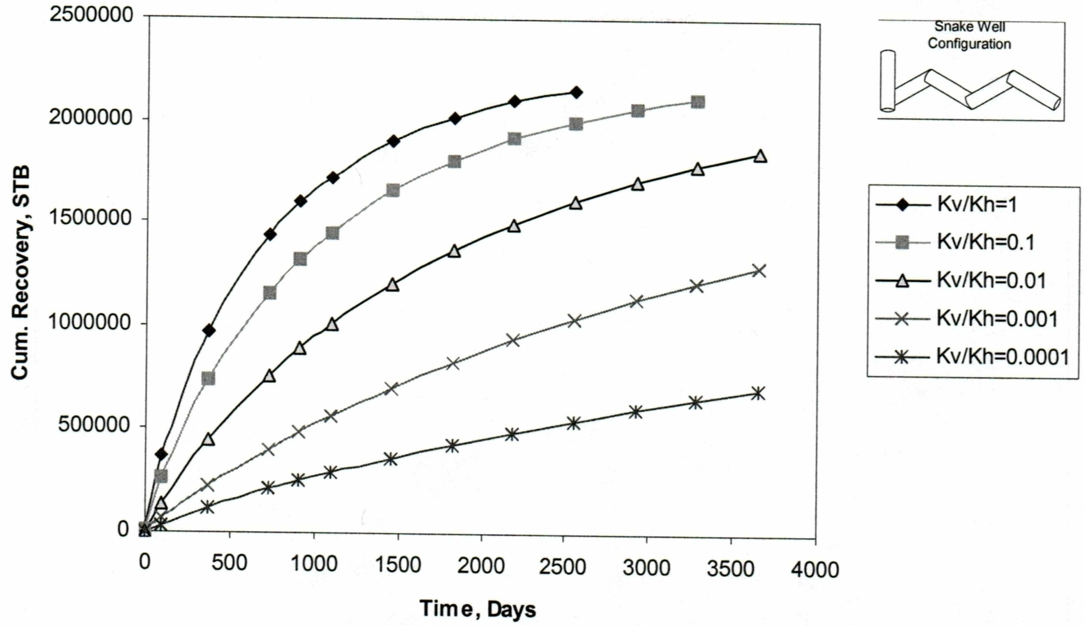

Figure 4.33: Cumulative Recovery Vs Time, Snake Well Configuration 4 Segments, Influence of Permeability Anisotropy.

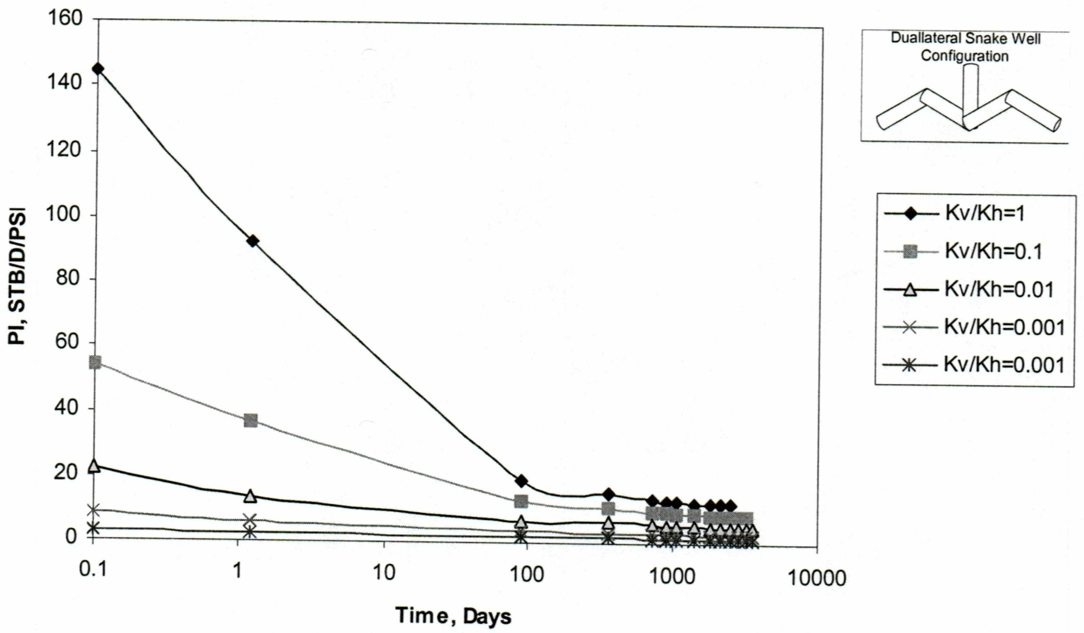

Figure 4.34: PI Vs Time Duallateral Snake Well Configuration 4 Segments, Influence of Permeability Anisotropy.

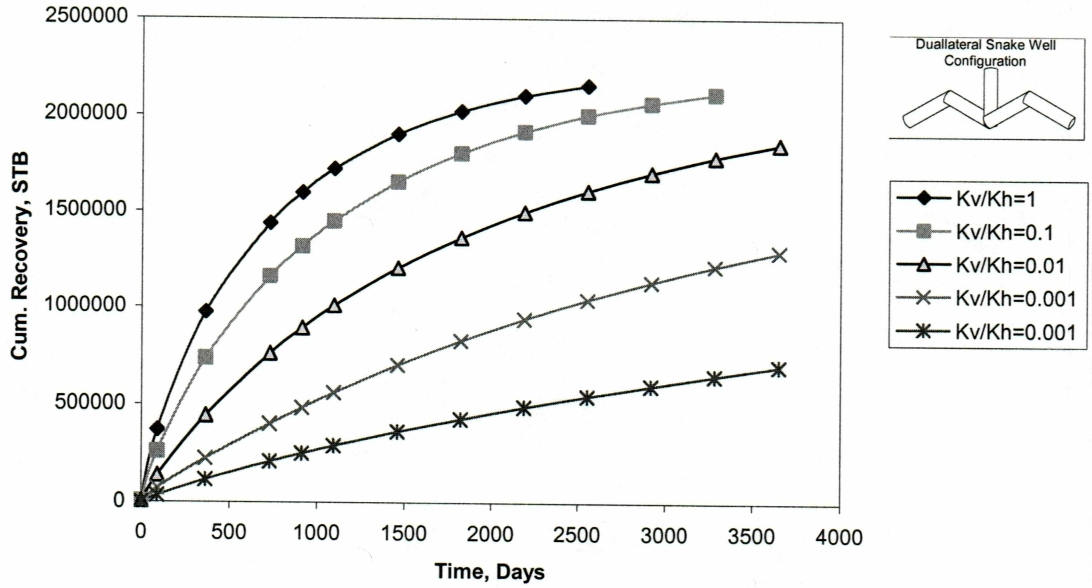

Figure 4.35: Cumulative Recovery Vs Time, Duallateral Snake Well Configuration 4 Segments, Influence of Permeability Anisotropy.

Fig. 4.34 and 4.35 depict productivity index and cumulative production for duallateral snake well configuration with 4 segments. It shows a similar trend of decrease in productivity with decrease in K_v/K_h ratio to that of snake well as seen in the previous section.

Fig. 4.36 and 4.37 show productivity index and cumulative production for a multilateral snake well with 4 segments. It is seen that as the K_v/K_h ratio decreases, the productivity index and the cumulative production decreases.

From Fig. 4.38 and 4.39 it is seen that for a snake well with 8 segments as the anisotropy ratio decreases, the productivity index and the cumulative production decreases.

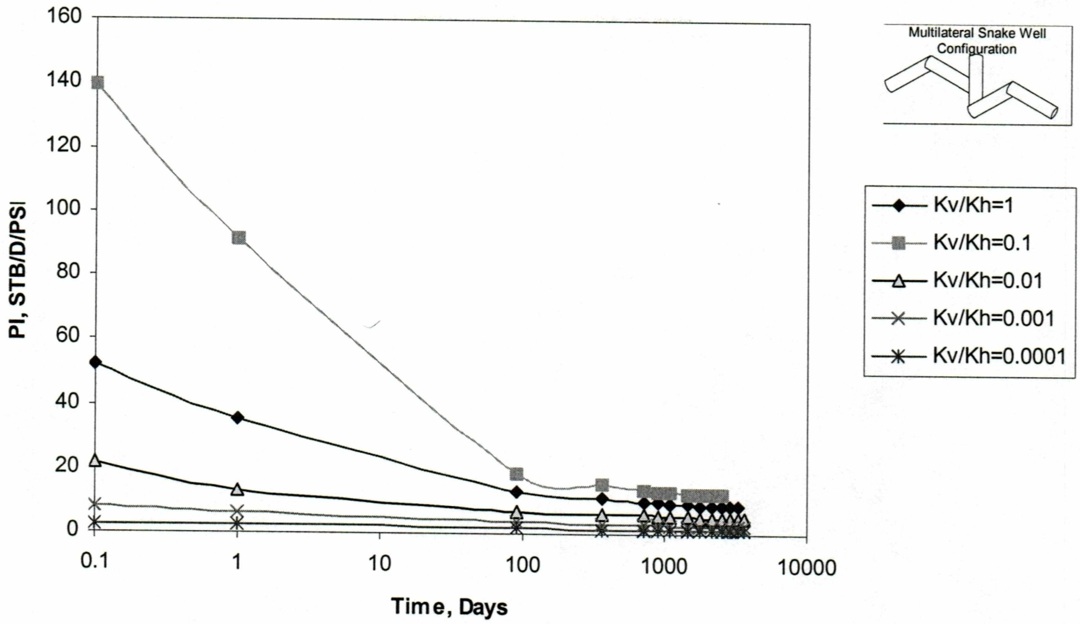

Figure 4.36: PI Vs Time, Multilateral Snake Well Configuration 4 Segments, Influence of Permeability Anisotropy

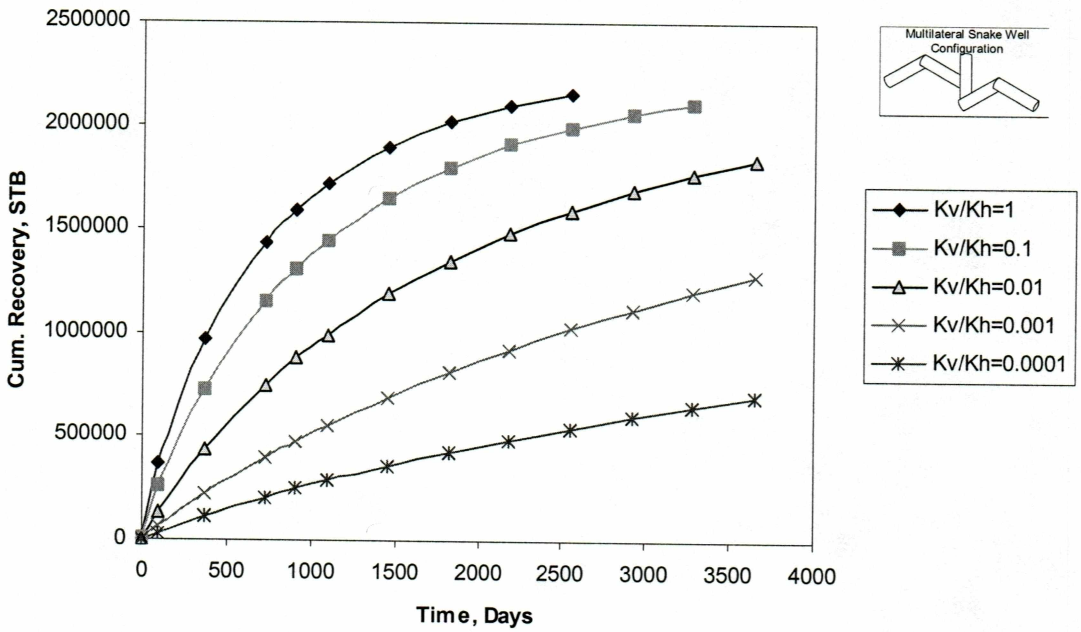

Figure 4.37: Cumulative Recovery Vs Time, Multilateral Snake Well Configuration, Influence of Permeability Anisotropy.

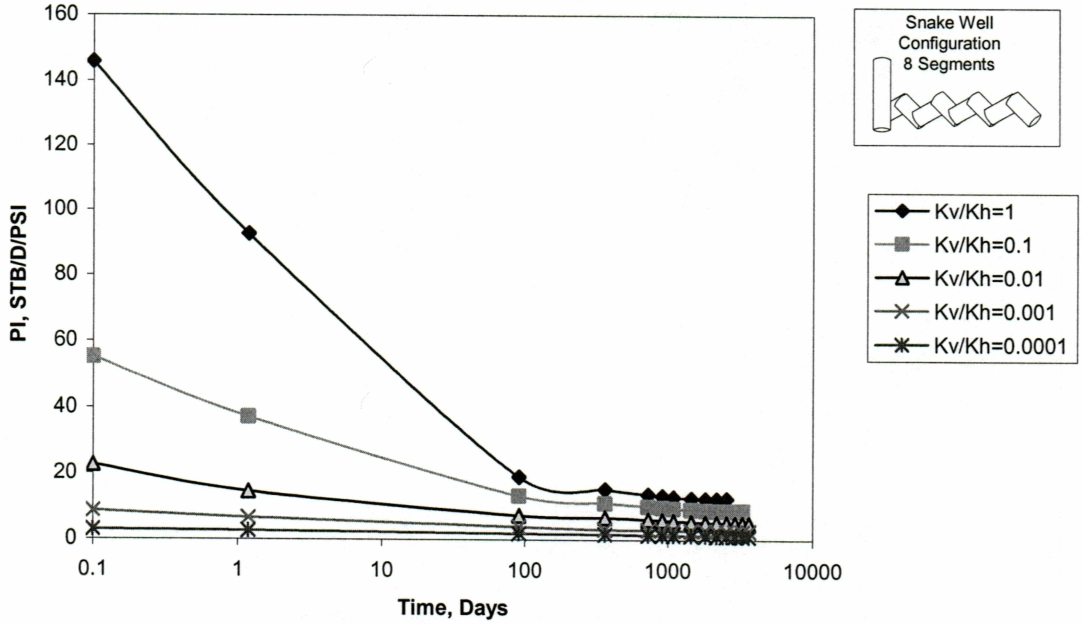

Figure 4.38: PI Vs Time Snake, Well Configuration 8 Segments, Influence of Permeability Anisotropy.

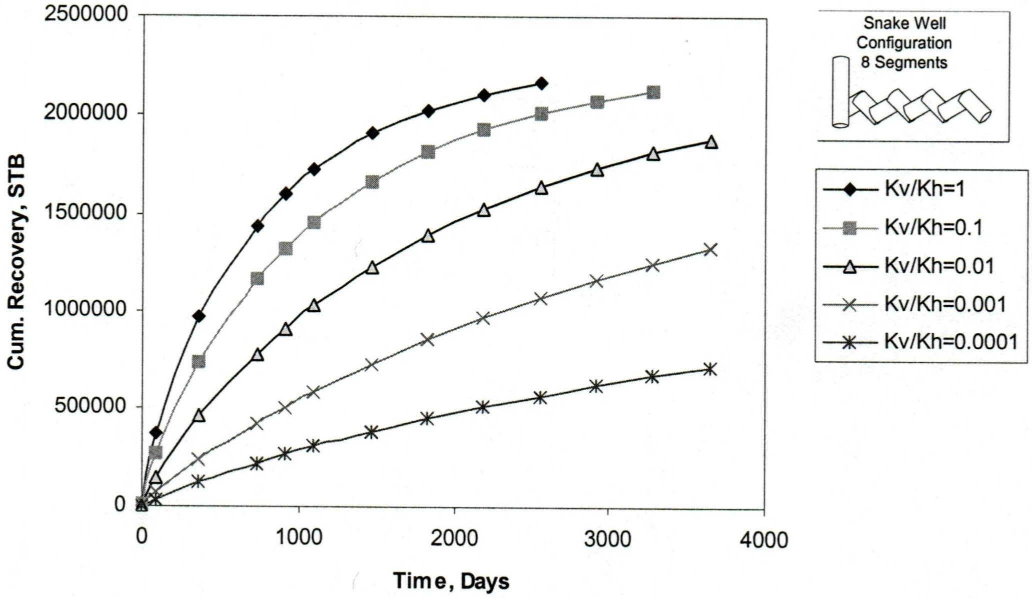

Figure 4.39: Cumulative Recovery Vs Time, Snake Well Configuration 8 Segments, Influence of Permeability Anisotropy.

The performance of a duallateral snake well with 8 segments (Fig. 4.40 and 4.41) is similar to that of the performance of snake well configuration with 8 segments (Fig. 4.38 and Fig. 4.39)

Fig. 4.42 and 4.43 depict the productivity index and cumulative production for a multilateral well with 8 segments. It is observed that drilling the snake shaped laterals at different intervals does not affect the productivity largely as compared to the productivity of duallateral snake well with 8 segments (Fig. 4.40 and 4.41)

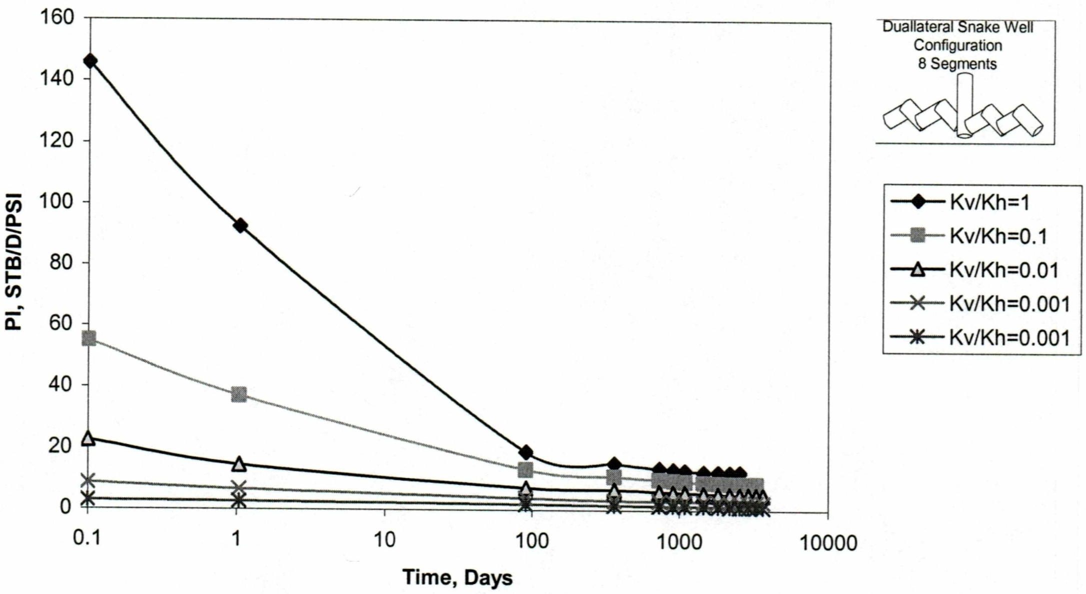

Figure 4.40: PI Vs Time Duallateral Snake, Well Configuration 8 Segments, Influence of Permeability Anisotropy.

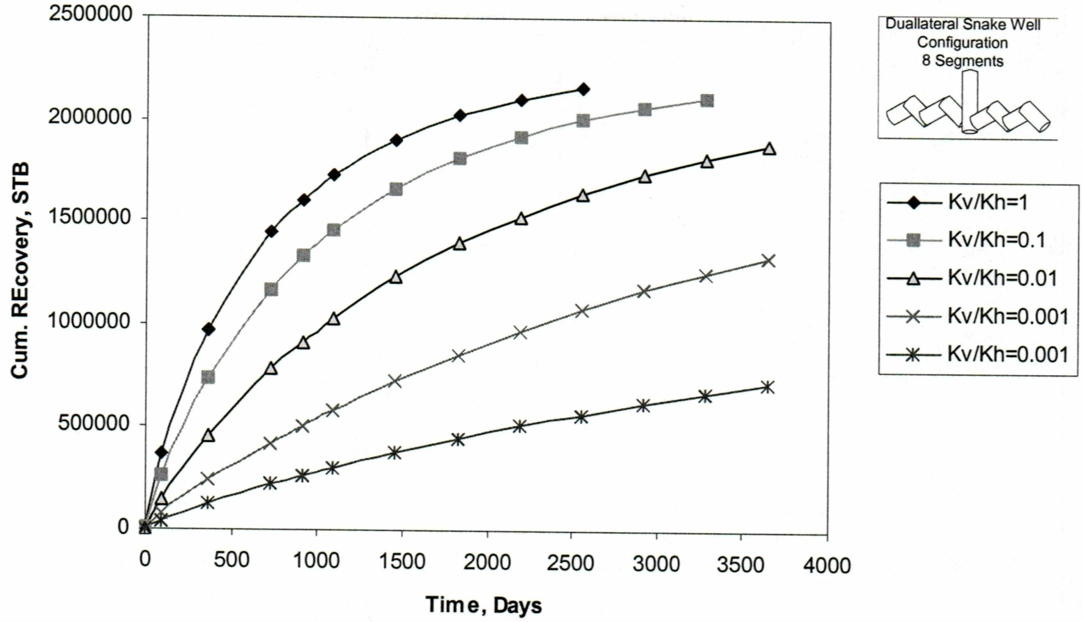

Figure 4.41: Cumulative Recovery Vs Time, Duallateral Snake Well Configurations, 8 Segments Influence of Permeability Anisotropy.

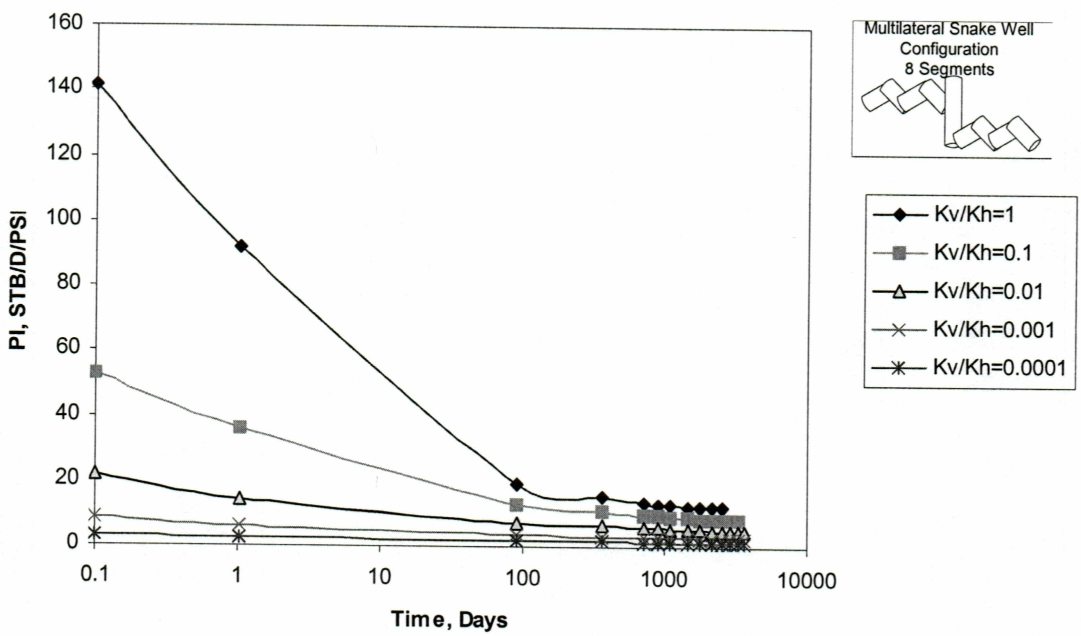

Figure 4.42: PI Vs Time, Snake Well Configuration, 8 Segments Influence of Permeability Anisotropy.

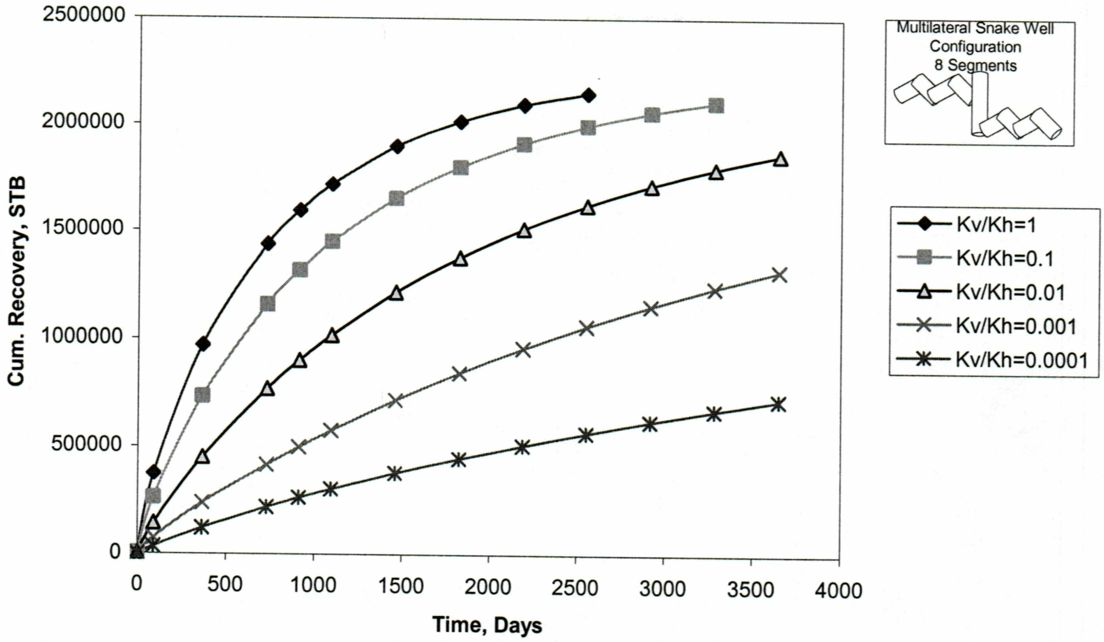

Figure 4.43: Cumulative Recovery Vs Time, Multilateral Snake Well Configuration 8 Segments, Influence of Permeability Anisotropy.

4.3.3 Performance of Fishbone configurations

This section discusses the performance of fish bone configurations under different permeability anisotropy scenarios.

From Fig. 4.44 and Fig. 4.45 we see that the productivity and the cumulative production for fishbone configuration decreases as the anisotropy ratio decreases. Both productivity index and cumulative production become linear for anisotropy ratio of 0.001 and 0.0001.

For duallateral fishbone configuration, the trend in productivity index and cumulative production (Fig.4.46 and Fig.4.47) is same as that of fishbone configuration (Fig.4.44 and Fig.4.45)

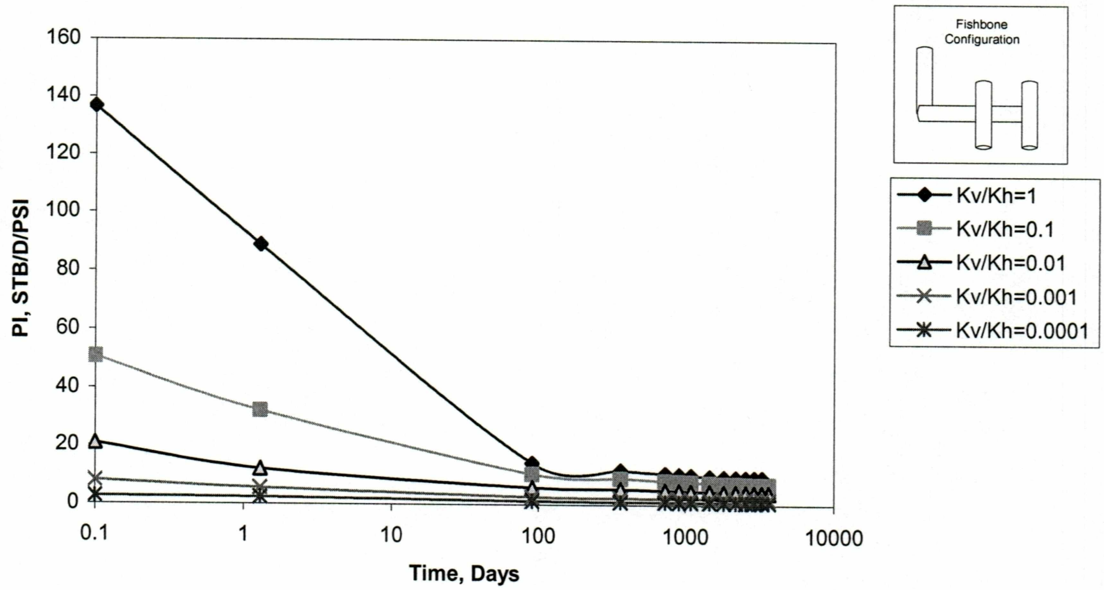

Figure 4.44: PI Vs Time, Fishbone Configuration Influence of Permeability Anisotropy.

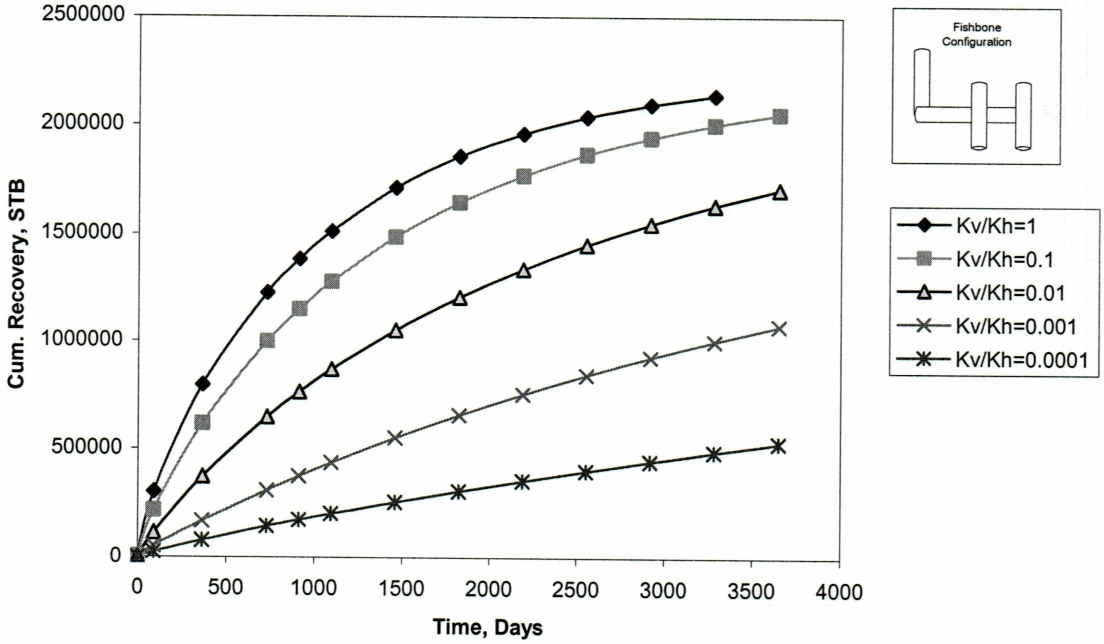

Figure 4.45: Cumulative Recovery Vs Time, Fishbone Configuration, Influence of Permeability Anisotropy.

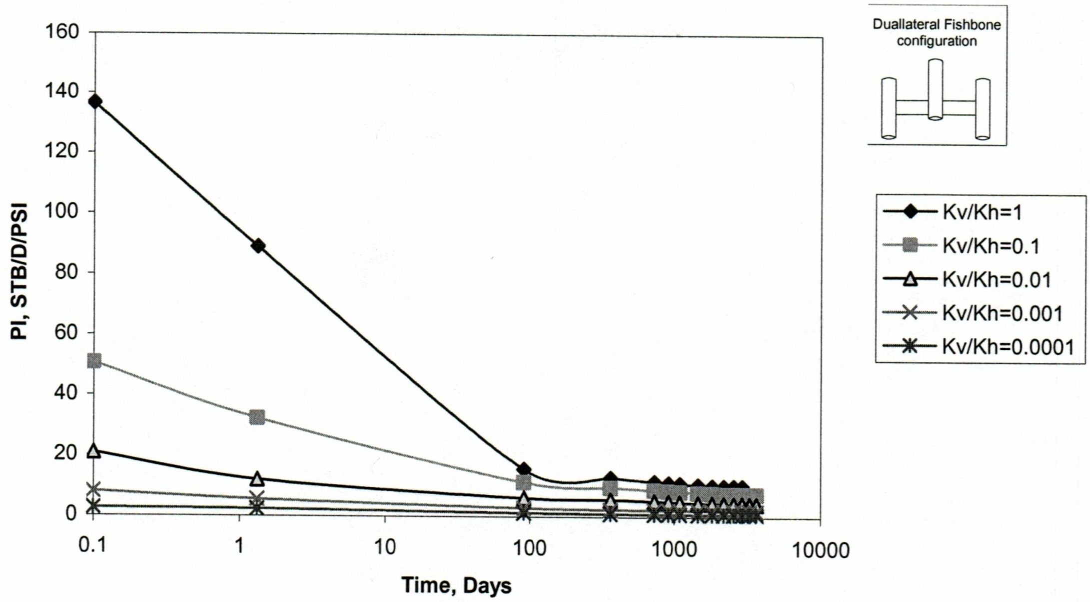

Figure 4.46: PI Vs Time, Duallateral Fishbone Configuration, Influence of Permeability Anisotropy.

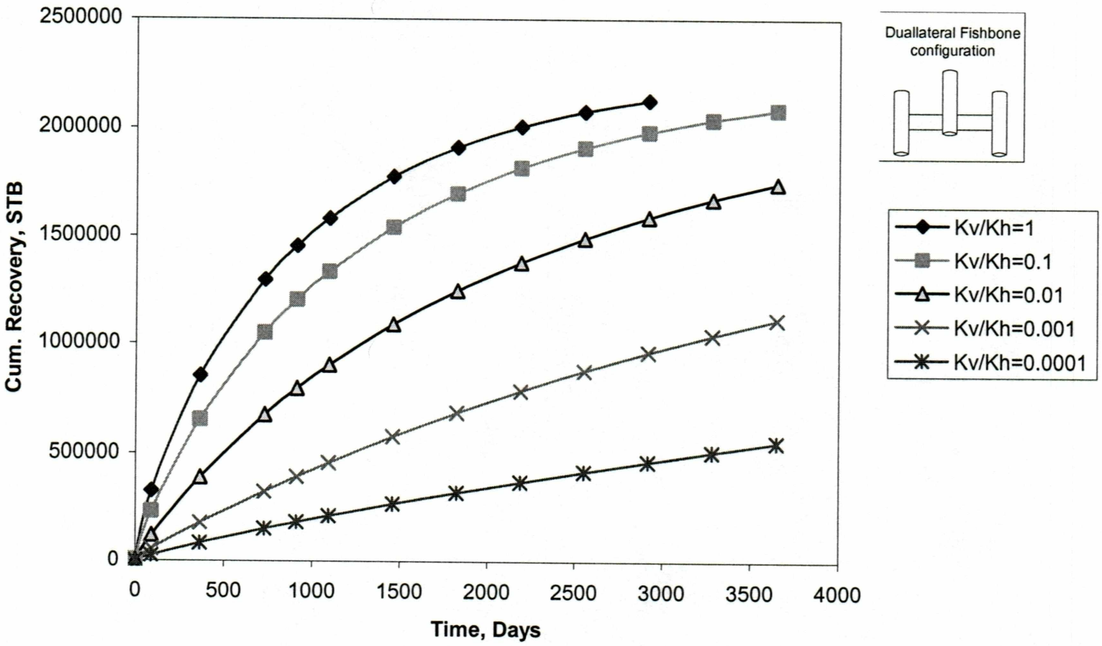

Figure 4.47: Cumulative Recovery Vs Time, Duallateral Fishbone Configuration, Influence of Permeability Anisotropy.

Multilateral fishbone configuration (Fig. 4.48) shows almost same performance to that of duallateral fishbone configuration (Fig. 4.46). The productivity index and cumulative production decrease with decrease in anisotropy ratio (Fig. 4.48 and Fig.4.49)

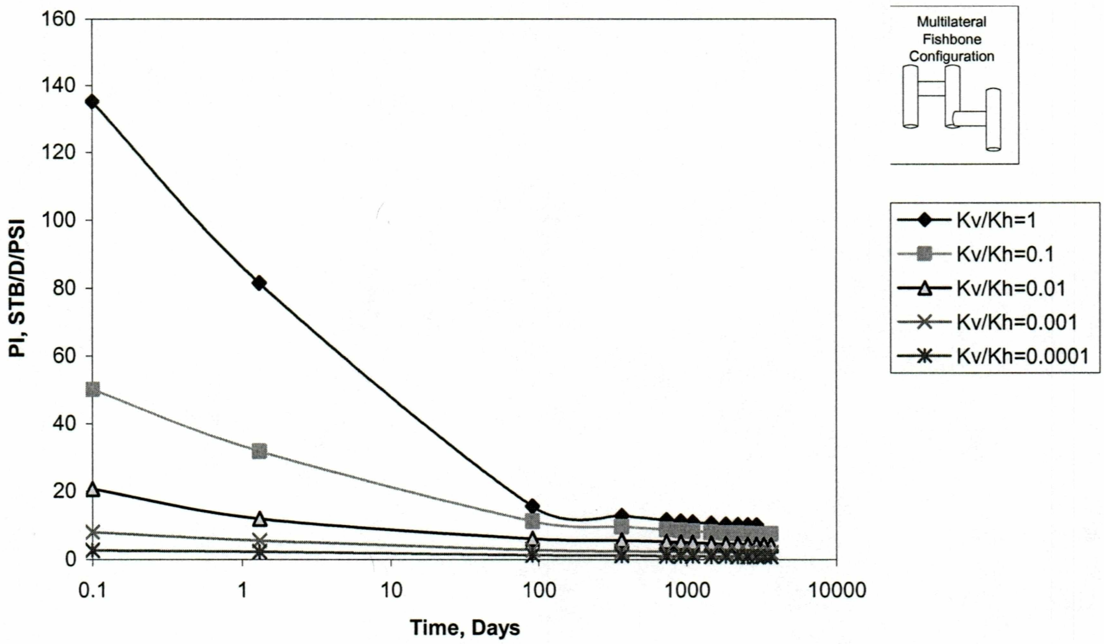

Figure 4.48: PI Vs Time, Multilateral Fishbone Configuration, Influence of Permeability Anisotropy.

4.3.4 Remarks

1. Based on the productivity index and cumulative production figures, it is seen that for all the configurations, the productivity decreases with decrease in permeability anisotropy ratio.
2. From the productivity index figures it is seen that the multilateral configuration wells show lower productivity than corresponding duallateral configurations.

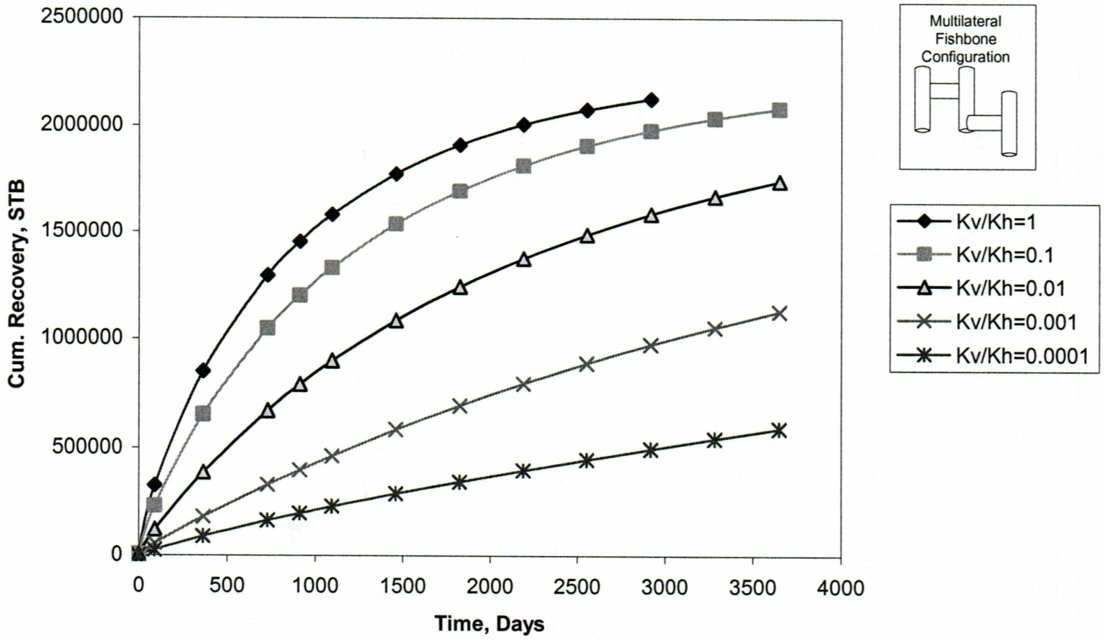

Figure 4.49: Cumulative Recovery Vs Time, Multilateral Fishbone Configuration, Influence of Permeability Anisotropy.

4.4 Influence of Partial Completion

The influence of partial completion was studied by comparing the productivity of fully perforated wells with those of partially completed wells. The effective length of perforated section is half that of the length of the horizontal section. Three scenarios of completions were considered

a. Wells perforated at the heel and toe.
b. Wells perforated at the center of the well.
c. Uniformly Distributed perforation.

Figure 4.50 shows a schematic of the three completion scenarios considered for a horizontal well. We consider only the horizontal and snake well configurations for this study.

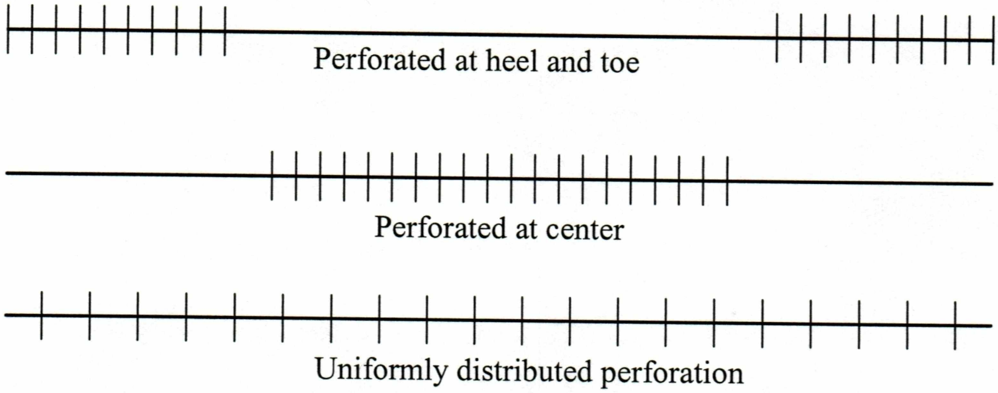

Figure 4.50: Schematic of partial completions considered for a horizontal well.

4.4.1 Performance of Horizontal Wells

Fig. 4.51 and 4.52 show the productivity index and cumulative production for the horizontal well configuration. It is seen that the productivity index of the three completion cases is approximately half that of the fully perforated case in the early period of production, however the cumulative production is more than half that of fully perforated case. The productivity index for well perforated at the center is equal to productivity index of well perforated uniformly along the length at the start of production but falls below that of the well perforated at the heel and toe. The uniformly distributed perforated case shows the higher cumulative production than cumulative production of well perforated at the center and at the heel and toe.

Fig. 4.53 and 4.54 show the productivity index and cumulative production for a duallateral well perforated at heel and toe, center and uniformly distributed along the lateral section, as compared to a fully perforated well. It is seen from Fig. 4.54 that the uniformly perforated case shows a higher cumulative production than well centrally perforated and at heel and toe. The cumulative production from the partially completed scenarios are more than half the cumulative production from a fully perforated well

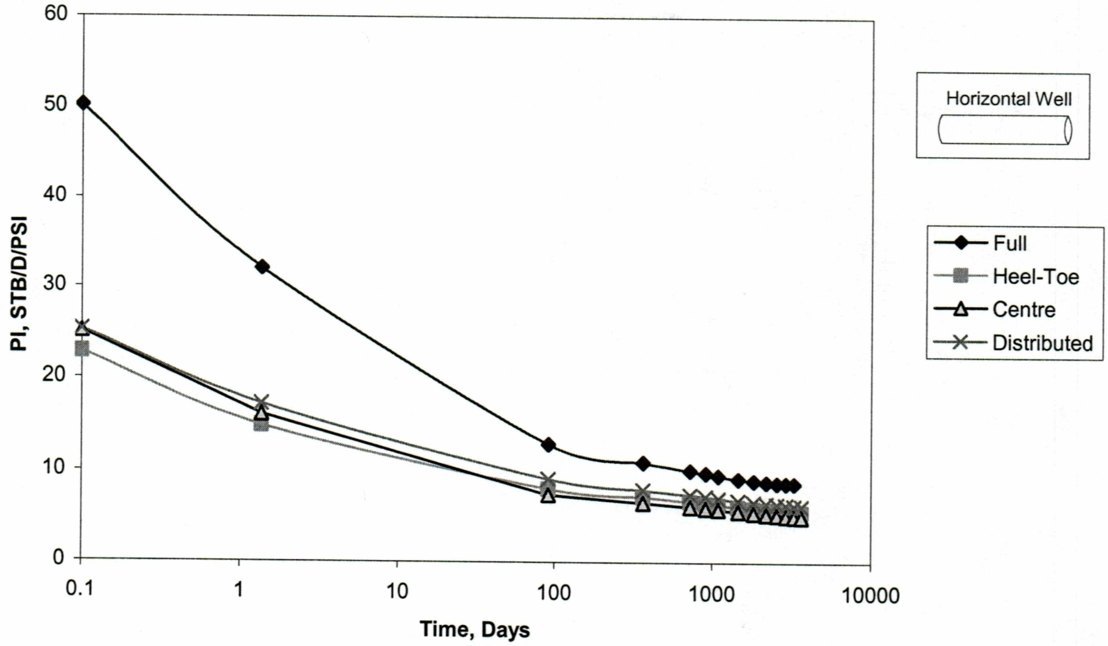

Figure 4.51: PI Vs Time, Horizontal Well Configuration, Partial Completions.

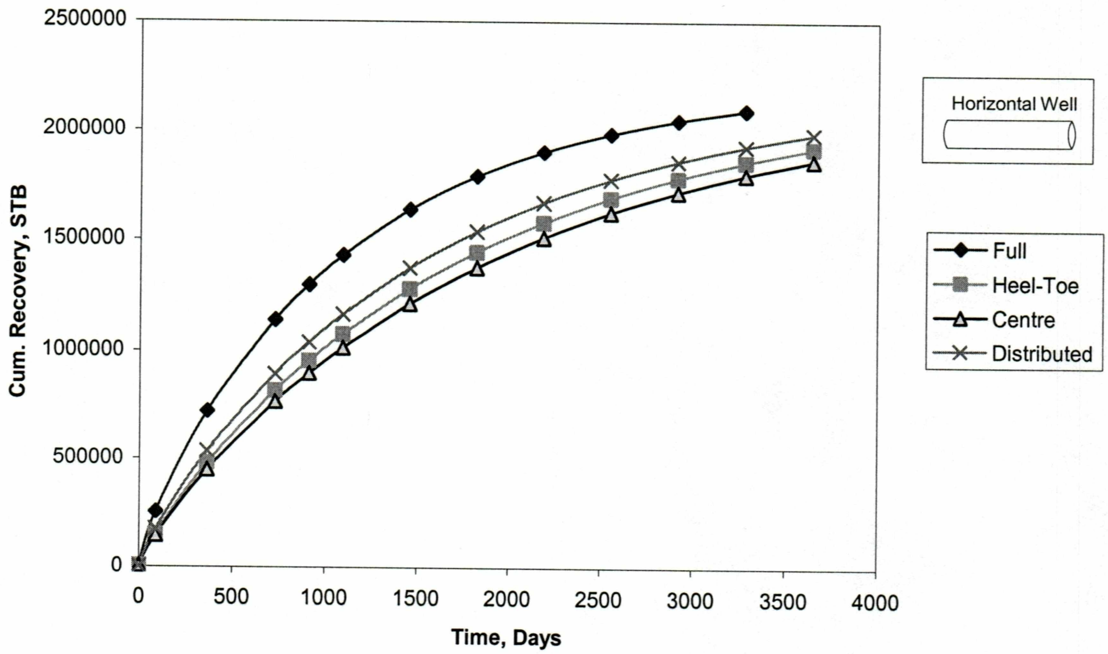

Figure 4.52: Cumulative Recovery Vs Time, Horizontal Well Configuration, Partial Completion.

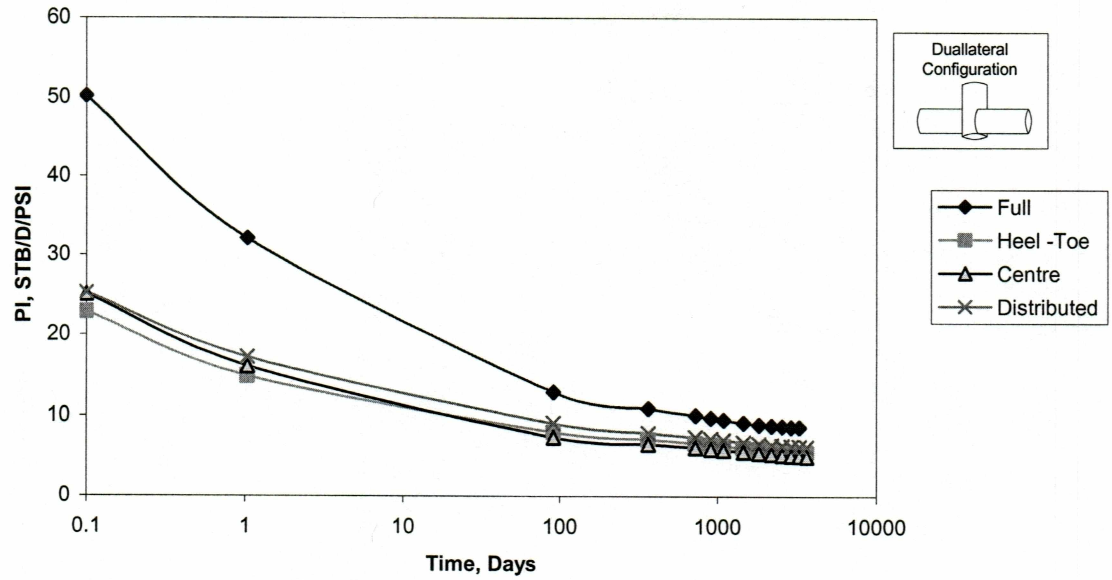

Figure 4.53: PI Vs Time, Duallateral Well Configuration, Partial Completion.

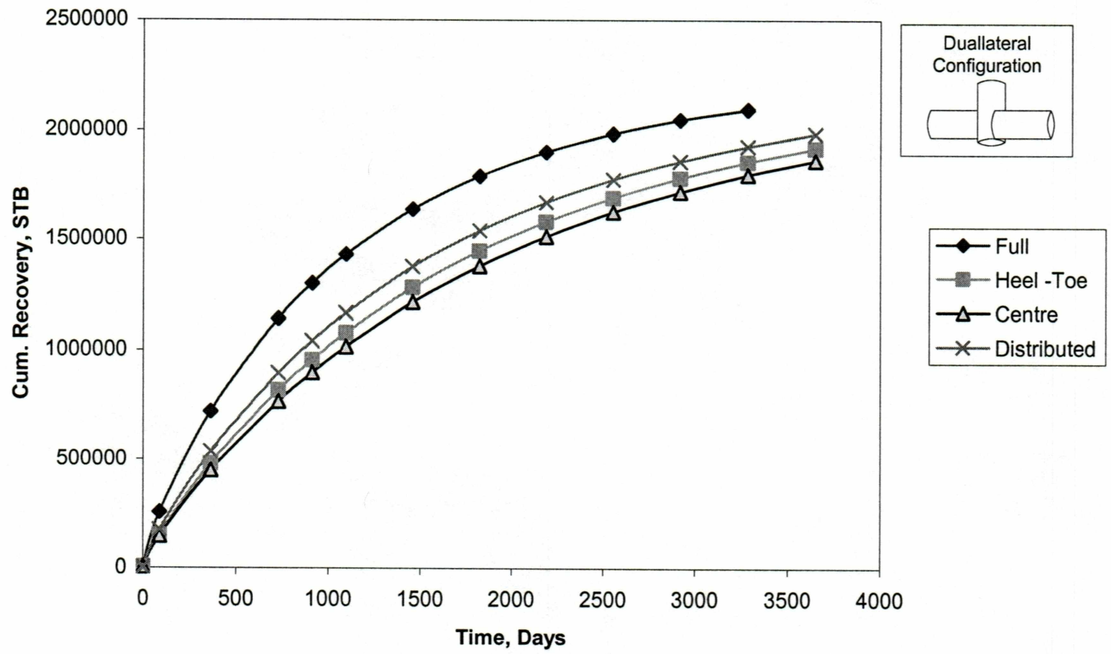

Figure 4.54: Cumulative Recovery Vs Time, Duallateral Well Configurations, Partial Completion.

From Fig. 4.55 it is seen that the productivity index for multilateral wells perforated at the center, heel and toe and uniformly along the length is equal at the start of the production. The productivity index of the centrally perforated case falls significantly below the uniformly perforated and well perforated at the heel and toe. There is no significant difference between the cumulative production from uniformly perforated and perforated at heel and toe (Fig. 4.56).

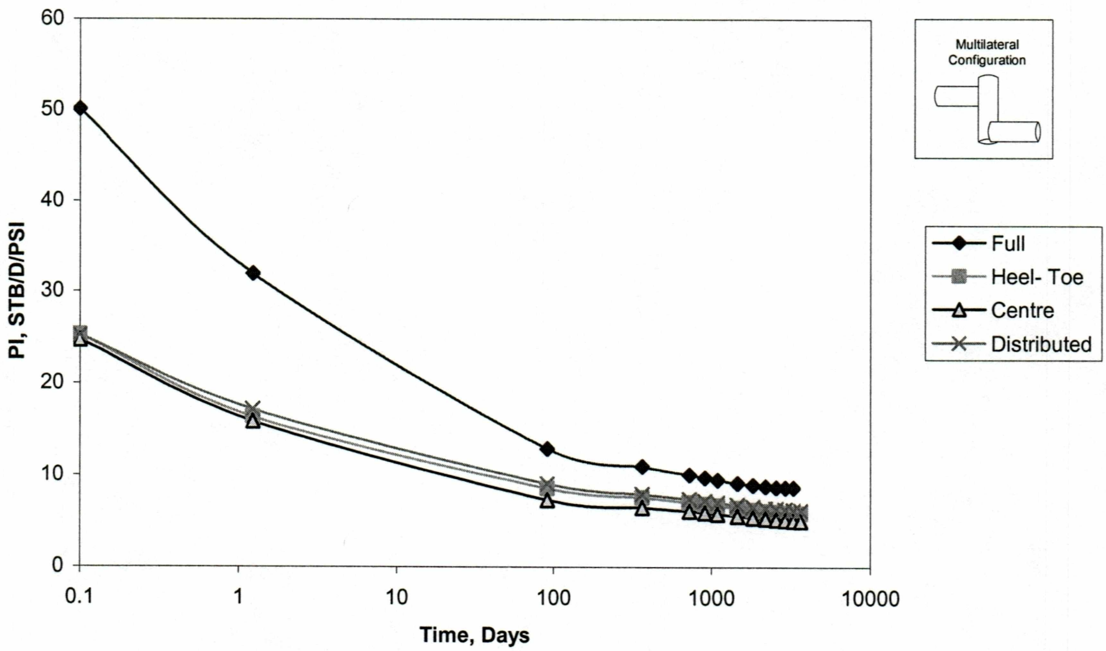

Figure 4.55: PI Vs Time, Multilateral Well Configuration, Partial Completion.

4.4.2 Performance of Snake Wells (4 Segments and 8 Segments)

Fig. 4.57 and 4.58 show the performance of 4 segmented snake well. It is seen that the productivity index for centrally perforate and uniformly perforated cases is equal at the start of production. However after 10 days of production the productivity index of the centrally perforated case falls below heel and toe perfoated case. The cumulative production of the uniformly perforated case is highest amongst the three partial completion cases considered.

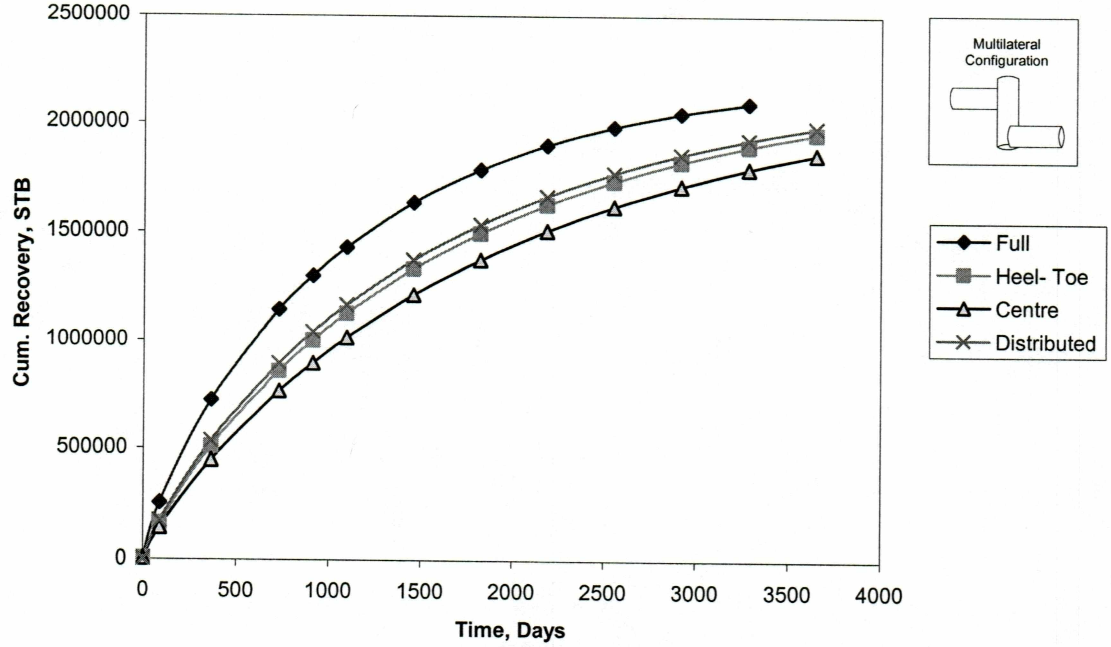

Figure 4.56: Cumulative Recovery Vs Time, Multilateral Well Configurations, Partial Completions.

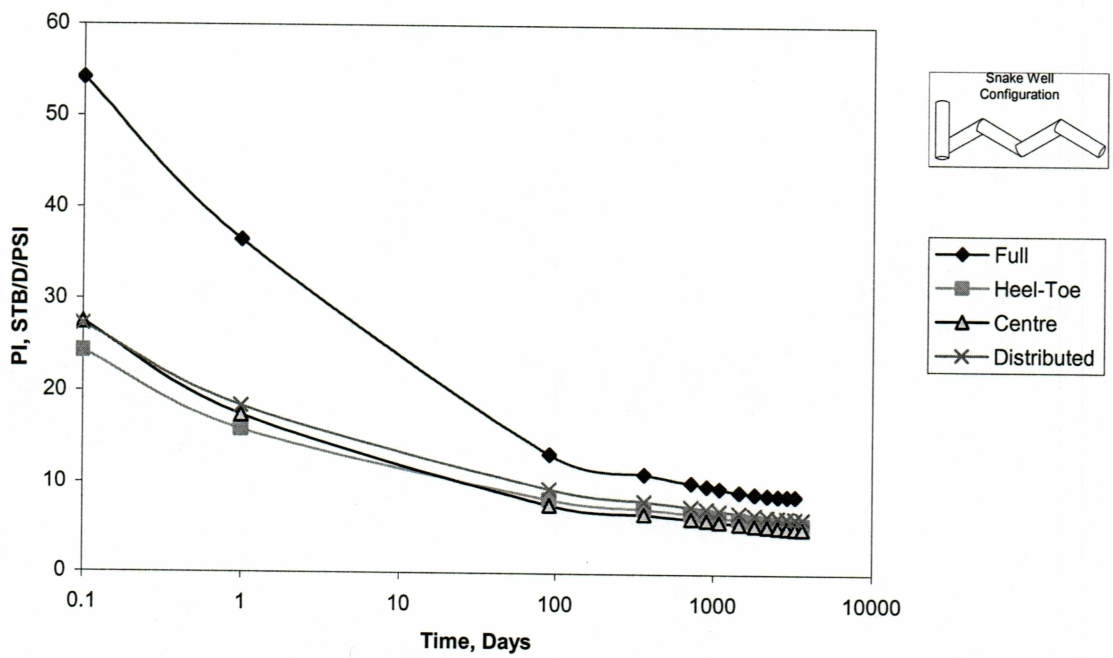

Figure 4.57: PI Vs Time, Snake Well Configuration 4 Segments, Partial Completion.

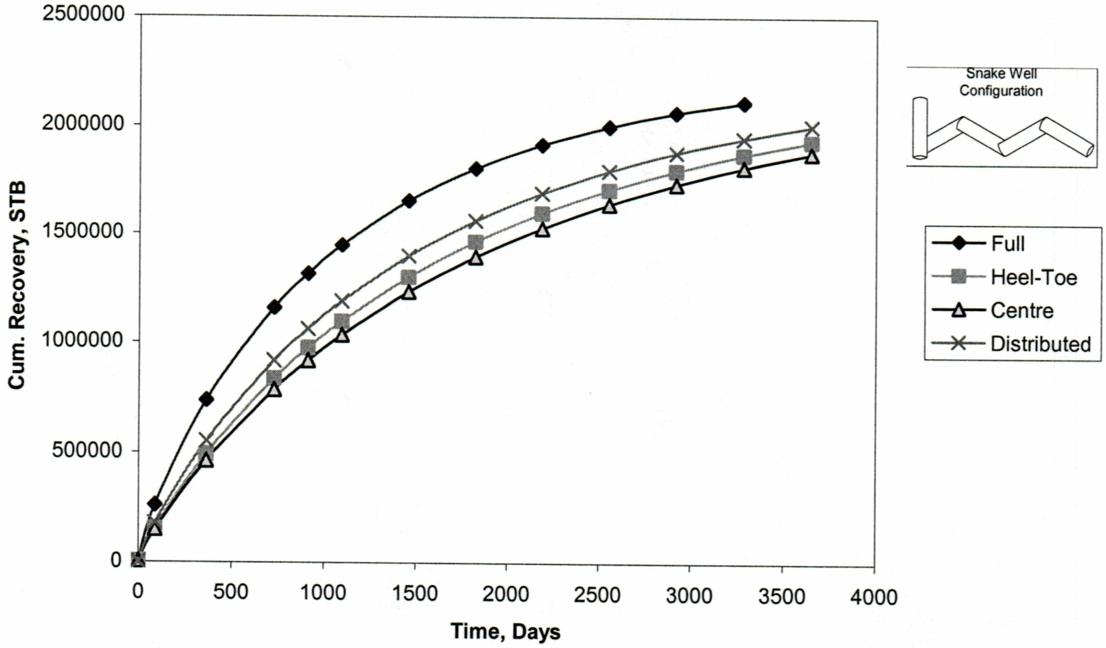

Figure 4.58: Cumulative Recovery Vs Time, Snake Well Configuration 4 Segments, Partial Completion.

Fig 4.59 and 4.60 show the productivity index and cumulative production from a duallateral snake well configuration for 3 partially perforated cases, in comparison with fully perforated well. The effective perforated length for all the three partial completion scenarios is half the effective perforated length of fully perforated well. It is seen from Fig. 4.60 that the cumulative production from the 3 partially perforated cases is more than half the cumulative production of fully perforated well.

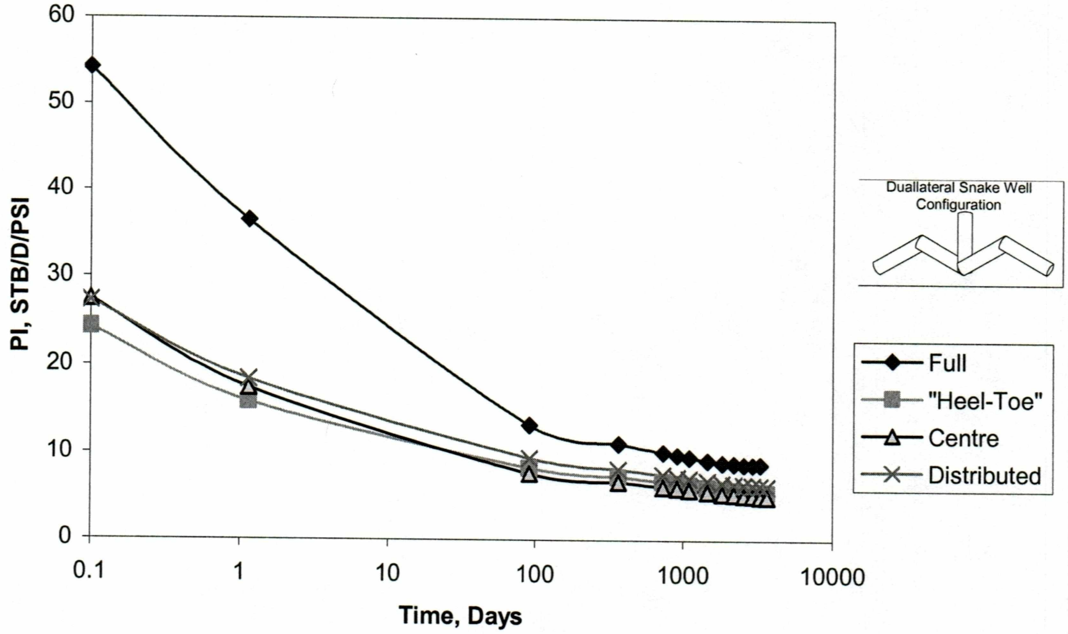

Figure 4.59: PI Vs Time, Duallateral Snake Well Configuration 4 Segments, Partial Completion.

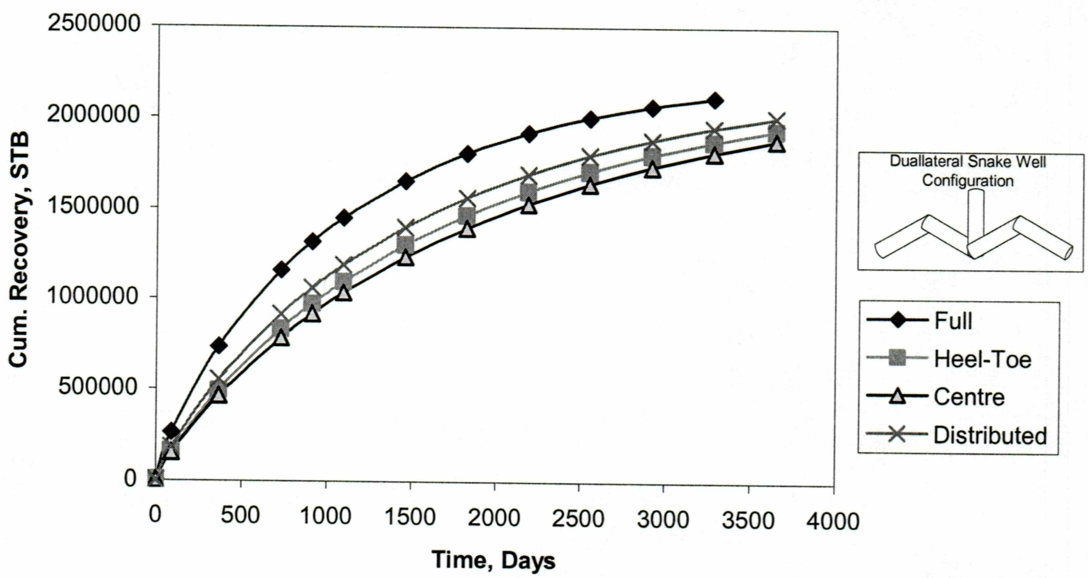

Figure 4.60: Cumulative Recovery Vs Time, Duallateral Snake Well Configuration 4 Segments, Partial Completion.

Fig. 4.61 and 4.62 show productivity index and cumulative production for multilateral snake well with 4 segments. It is seen that the productivity index for the centrally perforated case is equal to the uniformly perforated case at the start of production, but after 10 days of production the productivity index of the centrally perforated case falls below that of heel and toe perforated case. The cumulative production for the uniformly perforated case is higher than centrally perforated and heel and toe perforated case.

Fig. 4.63 and 4.64 depict the productivity index and cumulative production for an 8 segmented snake well with wells perforated centrally, perforated at heel and toe and perforated uniformly along the length of the well, in comparison with fully perforated well. The cumulative production for uniformly perforated case is higher than centrally perforated and heel and toe perforated cases. The cumulative production for all the 3 partial perforation scenarios is more than half the cumulative production from a fully perforated well.

Fig. 4.65 and 4.66 depict the productivity index and cumulative production for an 8 segmented duallateral snake well for three perforation cases, in comparison with fully perforated well. It is seen that the productivity index of centrally perforated case is equal to heel and toe perforated case at the start of the production. The cumulative production for the uniformly perforated case is higher than centrally perforated and heel and toe perforated cases.

Fig. 4.67 and 4.68 depict the productivity index and cumulative production for an 8 segmented multilateral snake well for three partial perforation cases, centrally perforated, perforated at heel and toe and uniformly distributed perforation in comparison with fully perforated well. It is seen that the productivity index of centrally perforated case is lower than the heel and toe perforated case after 1 day of production. The uniformly perforated case shows higher cumulative production than the centrally perforated and heel and toe perforated case.

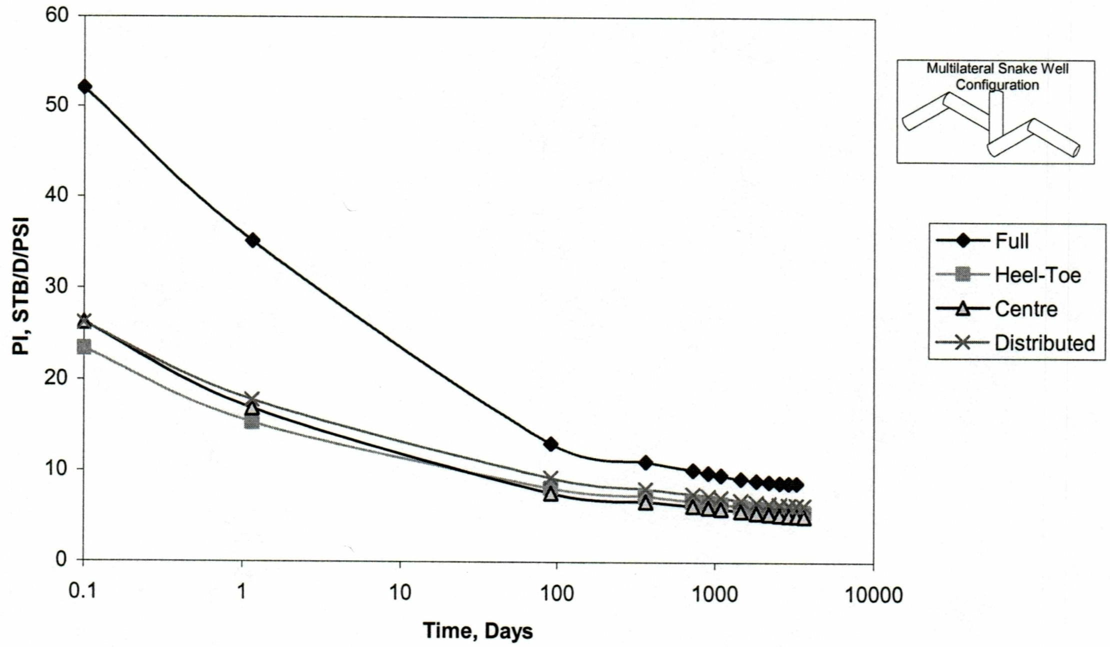

Figure 4.61: PI Vs Time, Multilateral Snake Well Configuration 4 Segments, Partial Completion.

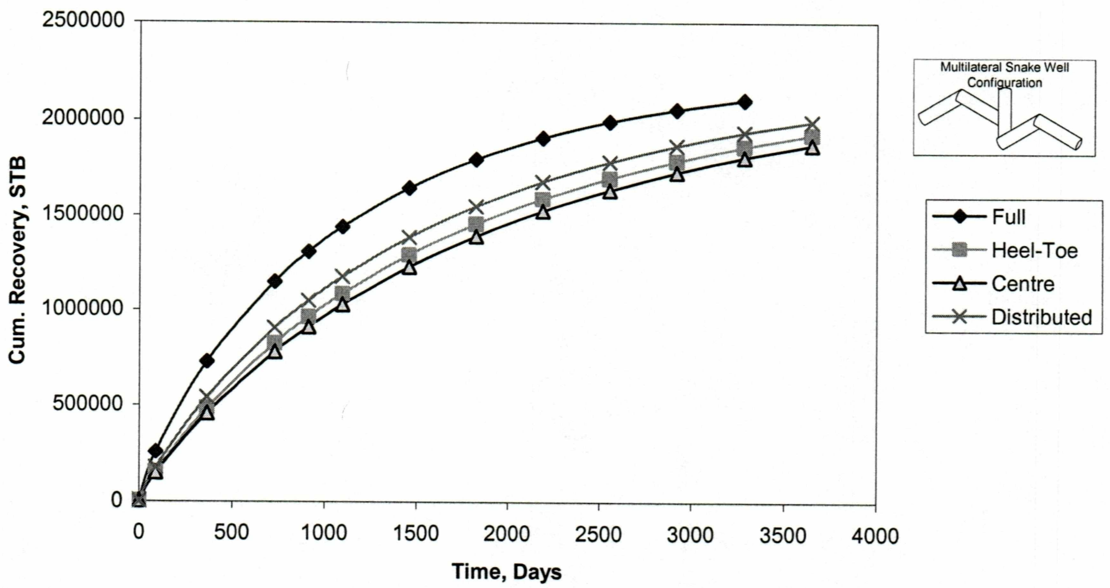

Figure 4.62: Cumulative Recovery Vs Time, Multilateral Snake Well Configuration 4 Segments, Partial Completion.

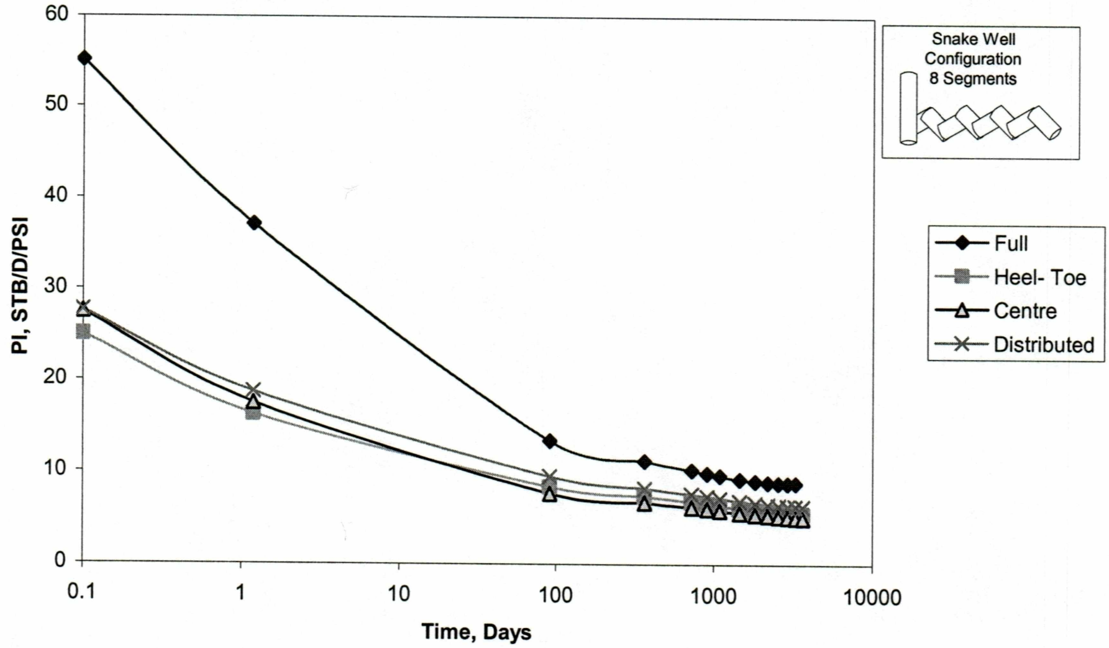

Figure 4.63: PI Vs Time, Snake Well Configurations 8 Segments, Partial Completion.

4.4.3 Remarks

1. For all configurations, it is observed that the uniformly perforated case showed higher cumulative production than centrally perforated and wells perforated at heel and toe.
2. For all the configurations it is seen that decreasing the effective producing length to half does not decrease the cumulative production by half. This is observed for all the three perforation cases.

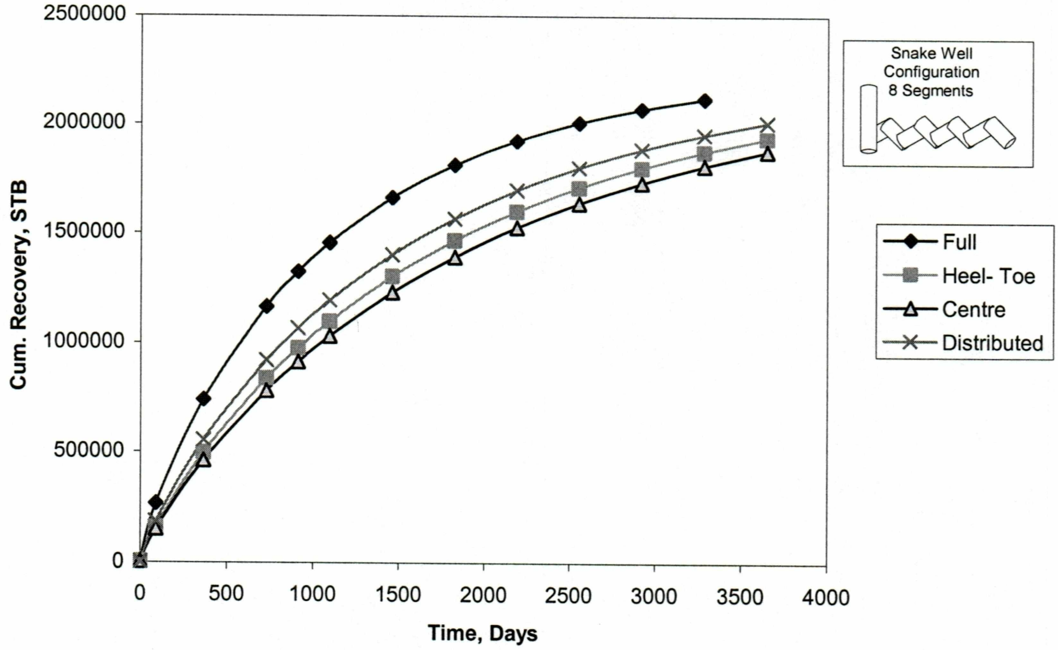

Figure 4.64: Cumulative Recovery Vs Time, Snake Well Configuration 8 Segments, Partial Completion.

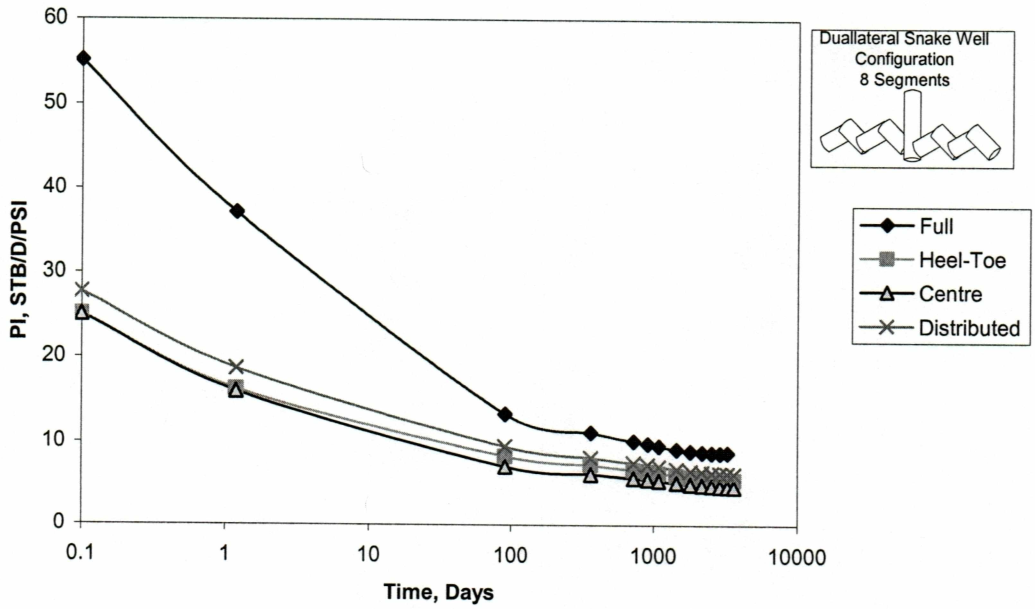

Figure 4.65: PI Vs Time, Duallateral Snake Well Configuration 8 Segments, Partial Completion.

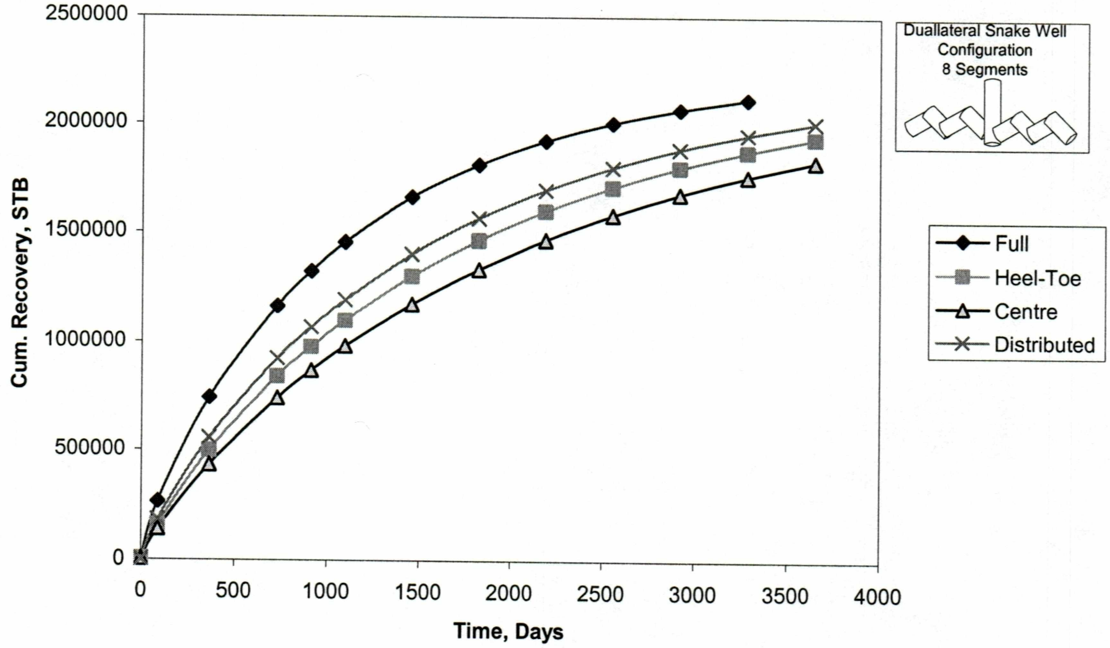

Figure 4.66: Cumulative Recovery Vs Time, Duallateral Snake Well Configuration 8 Segments, Partial Completion.

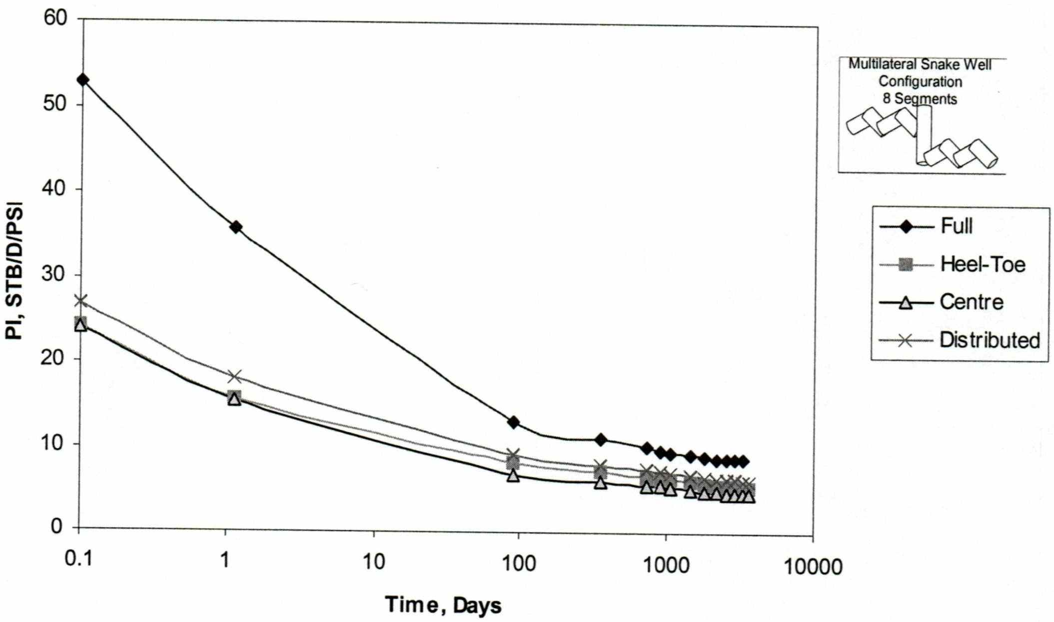

Figure 4.67: PI Vs Time, Multilateral Snake Well Configuration 8 Segments, Partial Completion.

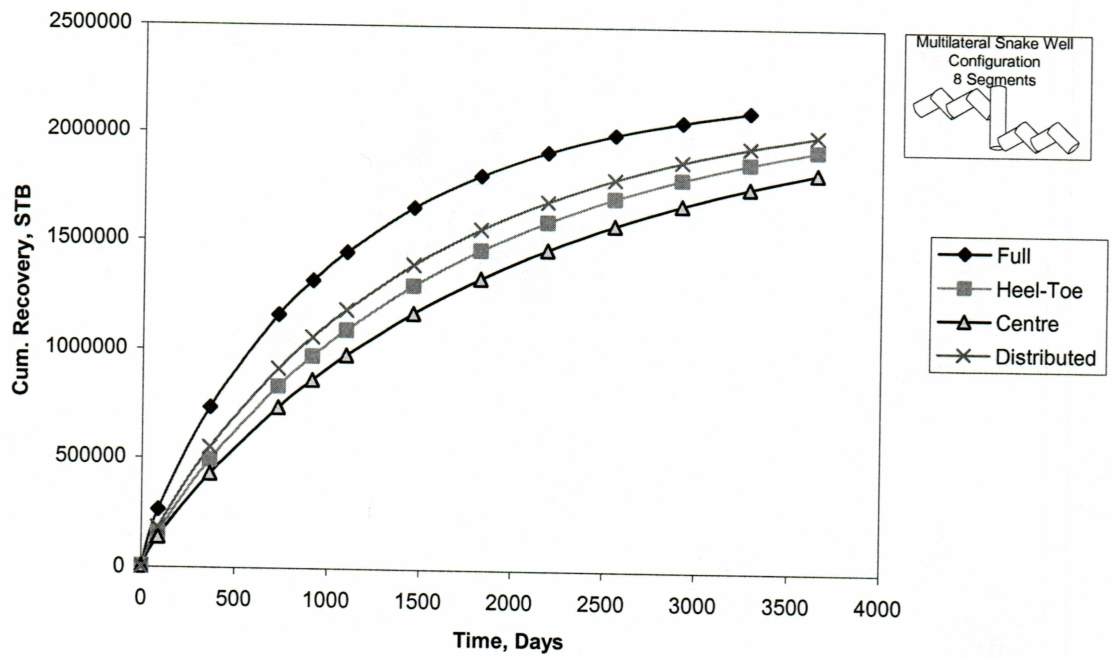

Figure 4.68: Cumulative Recovery Vs Time, Multilateral Snake Well Configuration 8 Segments, Partial Completion.

4.5 Influence of Well Length in Anisotropic Formation

We evaluated the performance of wells by varying the lengths of the wells. For horizontal, duallateral and multilateral wells we considered lengths of 594 ft, 1089 ft, 1584 ft and 2079 ft. For snake wells with 4 segments, length of one undulated segment is equivalent to the 594 ft of horizontal well. So, to study the impact of well length on the productivity of snake wells with 4 segments, we consider wells with 1, 2, 3 and 4 segments. Similarly, the length of 2 undulated segments of snake wells with 8 segments is equivalent to 594 ft of horizontal well. Hence, we consider wells with 2,4,6 and 8 segments, for this study. The reservoir system for this study was highly anisotropic in the vertical direction and the permeabilities of the layers are presented in table 4.2. The permeabilities were arbitrarily assigned. Fishbone configurations were not considered.

To compare the performance of the unconventional configurations with that of horizontal well, we consider a ratio of the PI of unconventional wells to the PI of horizontal well.

Table 4.2 : Permeability values in z direction for performance evaluation of well length

Layer	1	2	3	4	5	6	7	8	9	10
Permeability	26.5	26.5	0.0265	265	26.5	2.65	265	0.265	26.5	26.5

4.5.1 Performance of Duallateral and Multilateral Wells

Fig. 4.69 shows the performance of a duallateral well configuration as compared to that of a conventional horizontal well. It is seen that as the length of the well increases the productivity improves and the performance of a duallateral well is equal to that of a horizontal well for a length of 2079 ft.

For a multilateral well, as seen in Fig. 4.70, there is a significant improvement of productivity for early time period. The productivity index increases with increase in well length. However the long term productivity falls below the productivity of the horizontal well because of the permeability difference of the layers in which the lateral sections are completed.

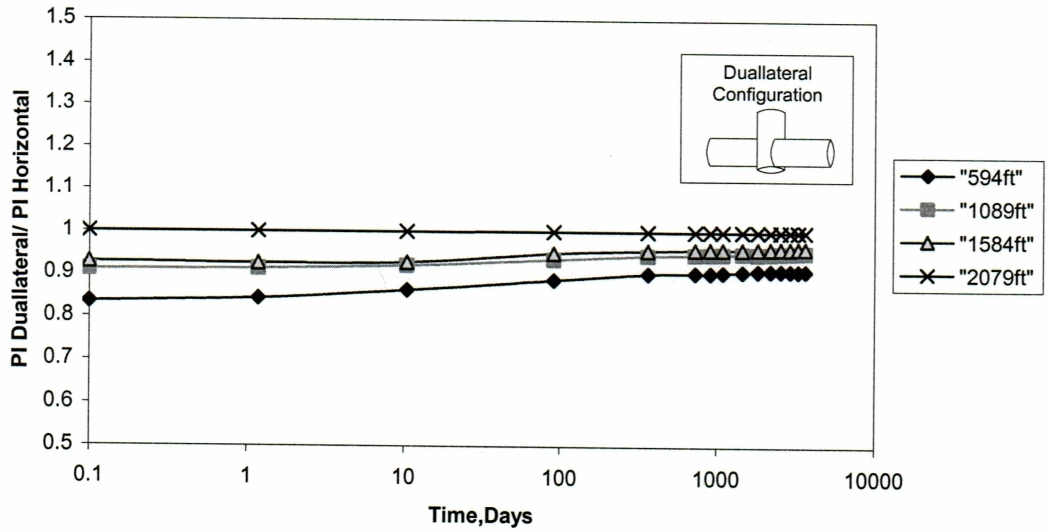

Figure 4.69: PI Ratio Vs Time, Duallateral Well Configuration

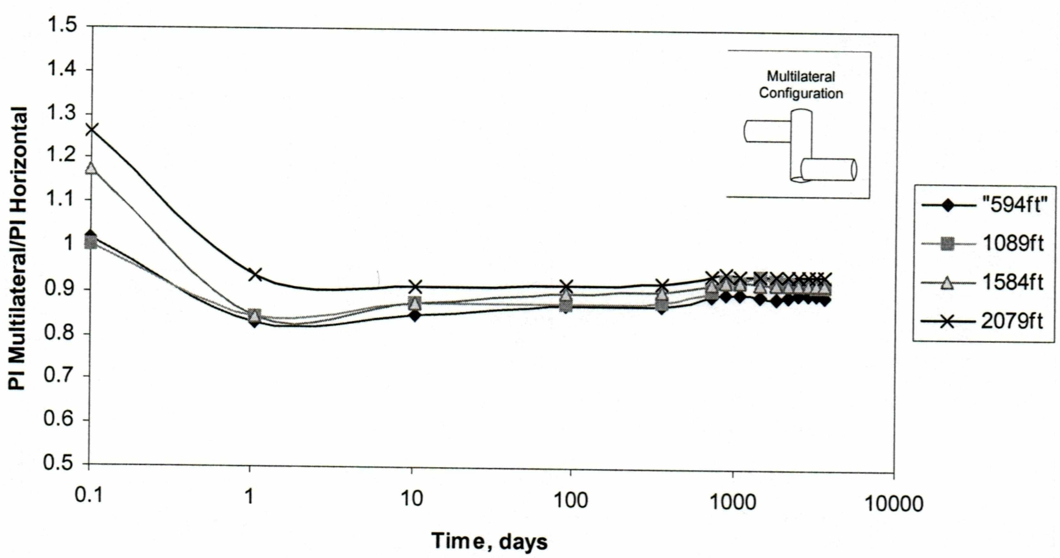

Figure 4.70: PI Ratio Vs Time, Multilateral Well Configuration

4.5.2 Performance of Snake Wells (4 Segments)

Fig.4.71 shows the performance of snake well. It is seen that the performance of the snake well with 2 segments is almost same as that of snake well with 4 segments. The productivity of well with 3 segments is higher than that of well with 1 segment, but lower than the productivity of wells with 2 and 4 segments, over a long term period. The long term productivity of this configuration falls below that of the horizontal well because the snake well penetrates three layers with different permeabilities.

Fig. 4.72 shows that performance of a well with one segment is almost identical to that of well with 4 segments and performance of wells with 1 and 3 segments is similar. This is because of the orientation of the segments which is compared with the performance of the horizontal well. The long term productivity of the well is equivalent to that of the horizontal well because of the permeability differences of the layers in which the well is completed.

For multilateral snake well, the long term productivity increases with increase in number of segments. However, there is no productivity improvement for a multilateral snake well configuration with 4 segments (Fig. 4.73) as compared to horizontal well. This is because the segments are completed in different layers having lower effective permeability where as the horizontal well is completed in only one layer. Also, as the number of segments in the well increase, the productivity index increases.

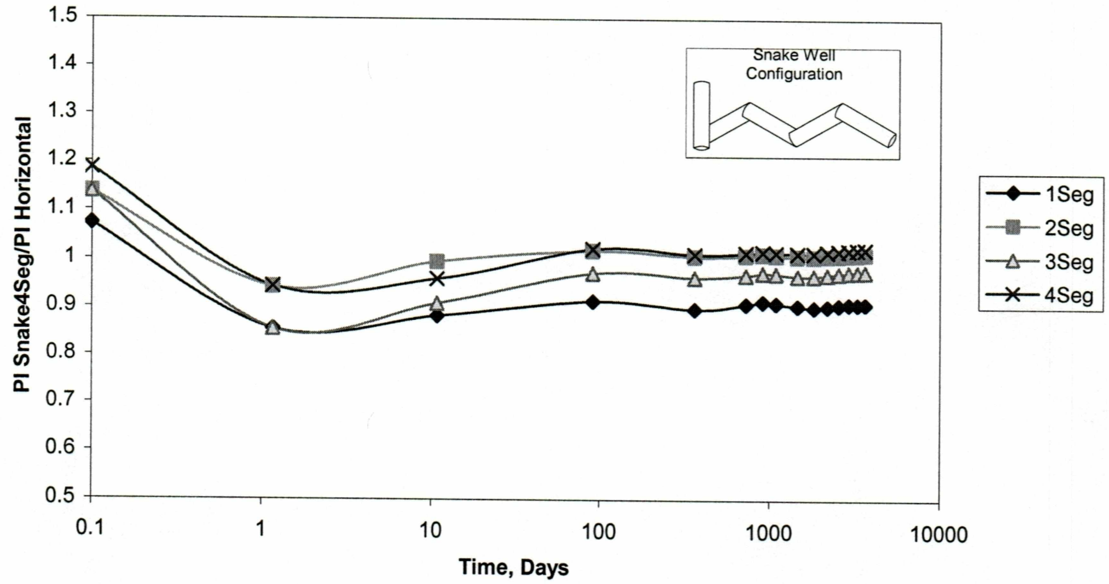

Figure 4.71: PI Ratio Vs Time, Snake Well 4 Segments

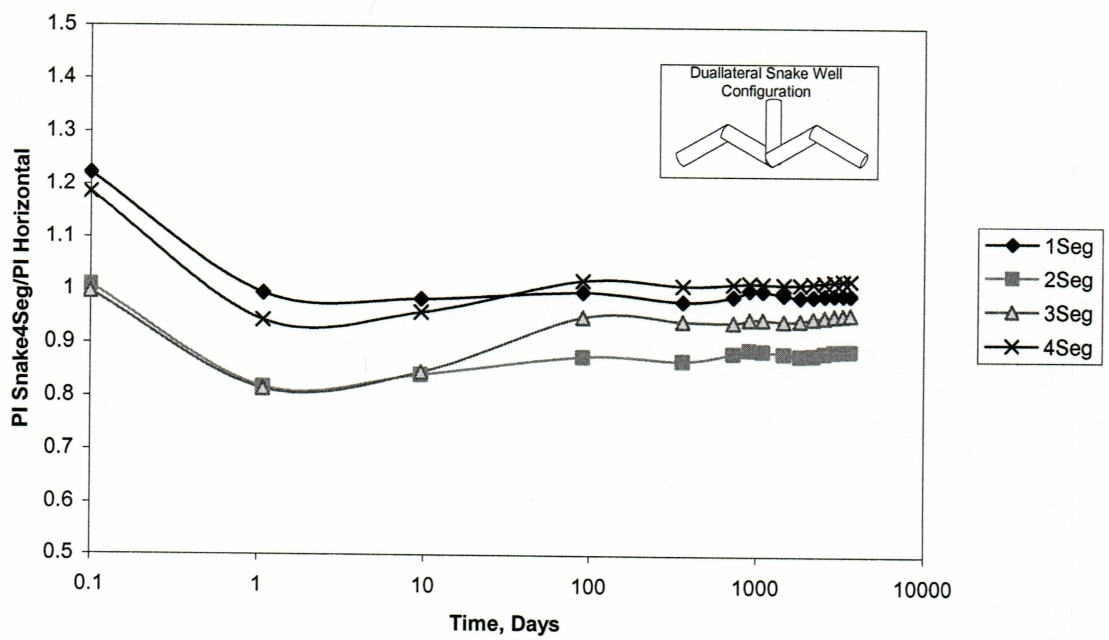

Figure 4.72: PI Ratio Vs Time, Duallateral Snake Well 4 Segments

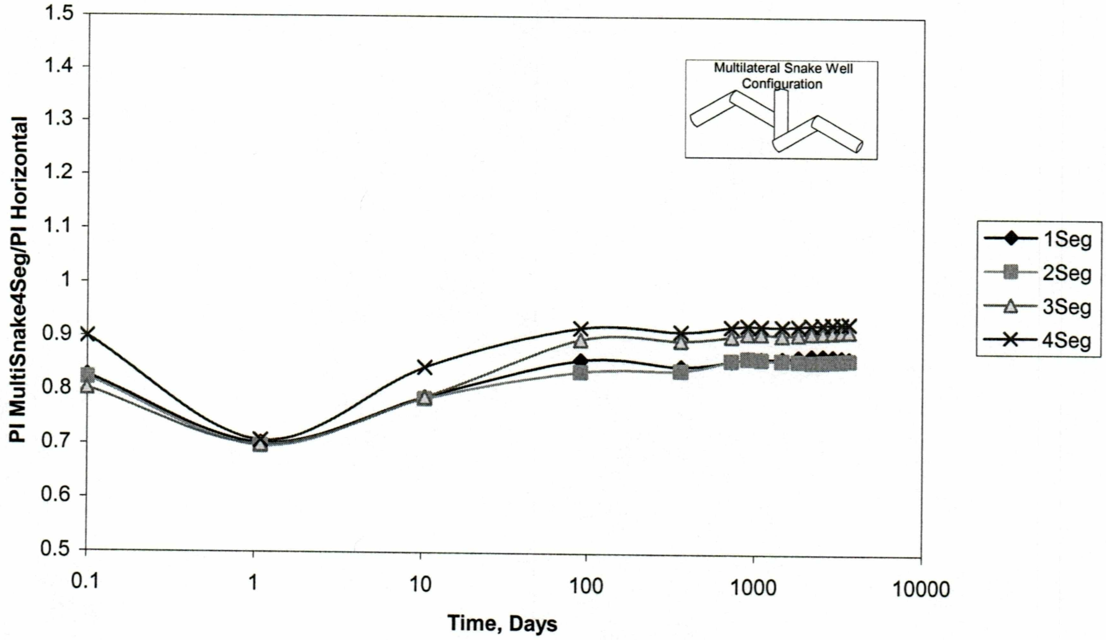

Figure 4.73: PI Ratio Vs Time, Multilateral Snake Well Configuration 4 Segments

4.5.3 Performance of Snake Wells (8 Segments)

Fig. 4.74 shows that there in no significant improvement in productivity as the number of segments increase. Also for a late time period the productivity index of the snake well with 8 segments is equal to horizontal well.

It is observed that for a duallateral snake well (Fig. 4.75), the productivity index increases with increase in number of segments. This is because of the orientation of the segments considered for comparison. Also the long term productivity of the well for 2, 4 and 6 segments is below that of equivalent horizontal well, because of the orientation of the segments in the payzone.

Fig. 4.76 shows that there is no productivity improvement for a multilateral snake well with 8 segments because the segments are completed in lower permeability zones.

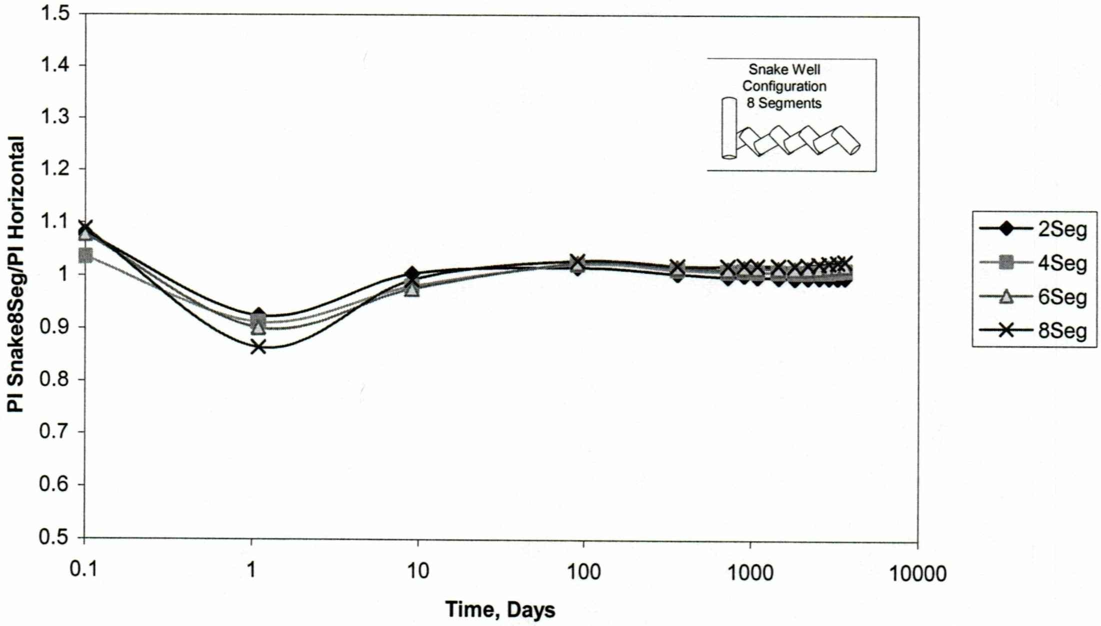

Figure 4.74: PI Ratio Vs Time, Snake Well Configuration 8 Segments

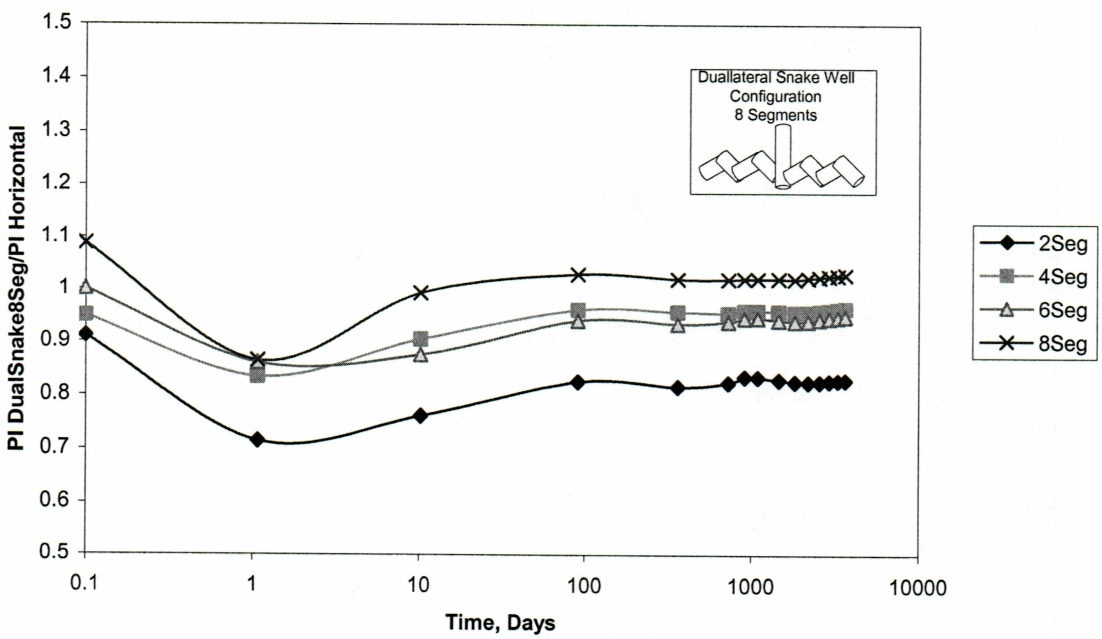

Figure 4.75: PI Ratio Vs Time, Duallateral Snake Well Configuration 8 Segments

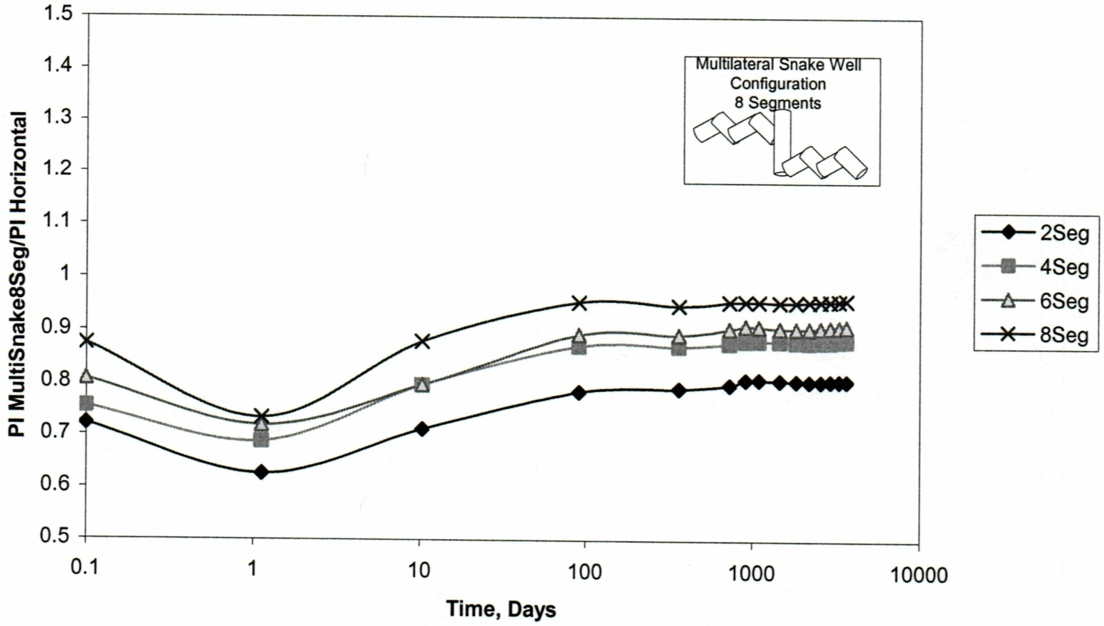

Figure 4.76: PI Ratio Vs Time, Multilateral Snake Well Configuration 8 Segments

4.6 Pressure Drop Correlation Evaluation

Friction losses can significantly affect the productivity of horizontal wells and wells of any configuration, if the well lengths are large or there is a presence of turbulent flow in the horizontal section. To evaluate the performance of horizontal wells for different pressure drop correlations, we use the specific productivity index model developed by Shah et al (2001)

The pressure drop in the horizontal section can be calculated using different correlations available in the literature. Choosing a proper friction factor correlation can also have a great impact on the well productivity calculation. To study this impact, we choose the following friction factor correlations.

Dikken

$$f = 0.079 N_{\mathrm{Re}}^{-\alpha} \quad (4.2)$$

Chen

$$f = 1/\left\{-4\left[\log\left[\varepsilon/3.7065 - 5.0452/N_{\mathrm{Re}} Log\left[\varepsilon^{1.1098}/2.8257 + (7.149/N_{\mathrm{Re}})^{0.8981}\right]\right]\right]\right\}^{-2}$$

(4.3)

Jain

$$f = 0.25\left[1.14 - 2\log\left[\varepsilon/D + 21.25 N_{\mathrm{Re}}^{-0.9}\right]\right]^{-2} \quad (4.4)$$

Eclipse

$$f = 1/\left\{-3.6\log\left[6.9/N_{\mathrm{Re}} + \left(\varepsilon/3.7D\right)^{10/9}\right]\right\}^{-2} \quad (4.5)$$

These correlations were introduced into Shah et al (2001) model to calculate well productivity. The following section describes the results.

4.6.1 Calculation of productivity index using Shah et al Model

Step 1

Horizontal Drainage Area

$$A_h = \pi(L/2 + R_{ev})(R_{ev})/43560$$

$$a = \frac{L}{2}\left[0.5 + \sqrt{0.25 + (2R_{eh}/L^4}\right]^{0.5}$$

Step 2

Basic Calculation

$$\beta = \sqrt{K_h/K_v}$$

$$\cosh^{-1}(X) = \ln\left[\frac{a + \sqrt{a^2 - (L/2)^2}}{L/2}\right]$$

Step 3

Calculation of flow rate (without friction effect)

$$Q' = \frac{0.00708 K_h h \Delta P / \mu Bo}{Cosh - 1(X) + \beta h / L \left(\frac{h}{2 \mu r_w'} \right)}$$

Step 4

Calculation of flow resistance

$$R_s = 2.921 e^{-15} L^{1.86} \left(\frac{\mu D}{\rho} \right)^{\alpha} \frac{\rho}{\pi^{1.75} D^5}$$

Step 5

Calculation of flow rate with flow resistance

$$Js(x) = \frac{Q' B_o}{\Delta P L}$$

$$Q_{X=0} = \frac{J_s(x) \Delta P (L - x)}{\cosh(L \sqrt{J_s(x) R_s})}$$

Step 6

Calculation of Reynolds number

$$Vx = \frac{4 Q B_o}{\pi D^2}$$

$$N_{\mathrm{Re}} = \frac{\rho V_x D}{\mu} = 0.1231 \frac{\rho Q}{\mu D}$$

Step 7

Calculation of friction pressure

$$f = 0.25 \left[1.14 - 2 \log \left[\varepsilon / D + 21.25 N_{\mathrm{Re}}^{-0.9} \right] \right]^{-2}$$

Here we use Jain's correlation. For the purpose of comparison, the same procedure is followed using other correlations mentioned earlier.

$$\frac{dP_w(x)}{dx} = \frac{2f\rho V_x^{\ 2}}{g_c D}$$

$$\Delta P_f(x)_{x=L} = \frac{dP_w(x)}{dx} L$$

Step 8

Calculating productivity index(PI)

$$Pe - P_H = Pe - P_H' + \Delta P_f(L)$$

Conventional PI without friction loss effect

$$J'_S = \frac{Q'}{(Pe - P_H')}$$

Specific PI with friction loss effect.

$$J_S = \frac{Q'}{Pe - P_H' + \Delta P_f(L)}$$

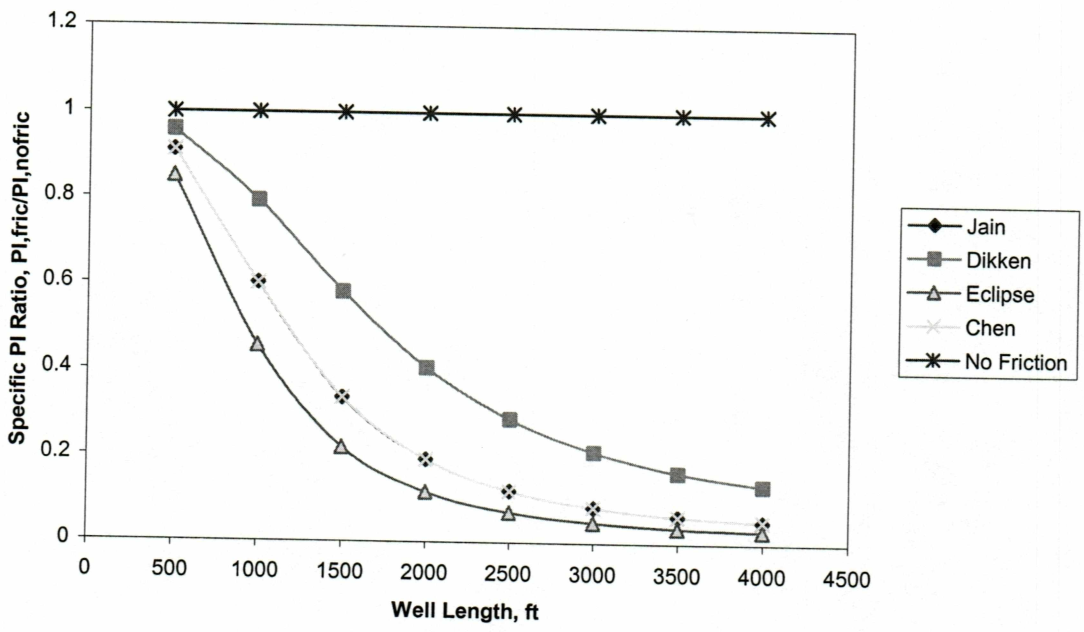

Figure 4.77: PI Ratio Vs Well Length, Friction and No Friction Case.

4.6.2 Remarks

The ratio of specific PI with friction to specific PI without friction was plotted as a function of well length. The detailed calculation spread sheet is presented in Table A-2. in Appendix

Fig. 5.77 shows that as the well length increases, there is significant difference between conventional PI and PIs with friction losses. The productivity losses as estimated by Dikken are minimum, losses given by Chen's and Jain's correlations are approximately the same with Jain's being on the higher side. Losses predictied by ECLIPSE are the highest. As we can see that there is also a significant difference between the losses predicted by individual correlations and choice of a particular correlation is a critical parameter in calculating productivity losses due to friction.

4.7 Guidelines

In this section guidelines are presented based on the results obtained from the simulation of the well performance for all the 12 well configurations studied. The guidelines are summarized in table 4.3.

Table 4.3: Guidelines to support decisions on optimum well configurations

Guidelines for Completing wells under different parameters studied			
Well Configuration	**Vertical Position in reservoir with Uniform Vertical Anisotropy**	**Partial Completion**	**Well length in reservoir with arbitrary Vertical Anisotropy**
Horizontal Well	Place well at position with lower Zw/h ratio	Perforate uniformly along the well length	
Duallateral Well	Place well at position with lower Zw/h ratio	Perforate uniformly along the well length	Without pressure drop considered, drill laterals as long as possible

Multilateral Well	Place well at position with lower Zw/h ratio	Perforate uniformly along the well length	Drill long laterals in high permeability zones
Snakewell 4 Segments	Place well at position with lower Zw/h ratio	Perforate uniformly along the well length	Drill more segments to increase productivity
Duallateral Snakewell 4 Segments	Place well at position with lower Zw/h ratio	Perforate uniformly along the well length	Orient the direction of segments to encompass higher permeability zones
Multilateral Snakewell 4 Segments	Place well at position with lower Zw/h ratio	Perforate uniformly along the well length	Orient the direction of segments to encompass higher permeability zones
Snakewell 8 Segments	Place well at position with lower Zw/h ratio	Perforate uniformly along the well length	Drill more segments to increase productivity
Duallateral Snakewell 8 Segments	Place well at position with lower Zw/h ratio	Perforate uniformly along the well length	Orient the direction of segments to encompass higher permeability zones
Multilateral Snakewell 8 Segments	Place well at position with lower Zw/h ratio	Perforate uniformly along the well length	Orient the direction of segments to encompass higher permeability zones
Fishbone Configuration	Place well at position with lower Zw/h ratio	Not evaluated	Not evaluated
Duallateral Fishbone configuration	Place well at position with lower Zw/h ratio	Not evaluated	Not evaluated
Multilateral Fishbone Configuration	Place well at position with lower Zw/h ratio	Not evaluated	Not evaluated

5. CONCLUSIONS AND RECOMMENDATIONS

5.1 Summary and Conclusions

1. Performance of horizontal, snake and fishbone configurations was studied in a 100 ft payzone by varying the location of the wellbore in the vertical section. It is observed that as the ratio of Zw/h is decreased the productivity increases. Based on cumulative production figures, it is observed that snake wells with 8 segments show best performance followed by snake wells with 4 segments, horizontal wells and fishbone configurations. Well configurations did not affect the productivity largely because of lack of heterogeneity in the reservoir model.

2. As the anisotropy ratio decreases the productivity index decreases. Below anisotropy ratio of 0.01, the productivity index for all the configurations is almost at the same value for same ratio of K_v/K_h.

3. It is seen that decreasing the perforated well length by half does not decrease the cumulative production by half.

4. Increase in frictional losses significantly decrease the productivity of a horizontal well. This effect is more pronounced as the length of the well increases. Selecting a particular friction factor correlation is a critical parameter in estimating productivity loss calculation in order to avoid overestimation or underestimation of productivity.

5.2 Recommendations

1. Study can be extended to heterogeneous systems with anisotropy in x, y and z directions.

2. Performance of the wells can be studied by combining the cases like well position with partial completion, well length with partial completion etc. This can lead to development of easy to use correlations of productivity for choosing a particular well configuration.

3. Pressure losses for different wellbore configurations can be studied.

NOMENCLATURE

A_{eq} = Equivalent well drainage area, ft^2

A = half major axis of drainage ellipse, ft

a_{eq} = reservoir width, ft

b_{eq} = reservoir length, ft

B_o = formation Volume factor, RB/STB

c' = shape factor conversion constant

C_A = Dietz's shape factor, dimensionless

C_{ACP} = shape factor, constant pressure case, dimensionless

Dq = flowrate dependent skin factor, dimensionless

D = inner diameter of wellbore, ft

f = Fanning friction factor

g_c = conversion factor, 32.1 lbm-ft/lbf-s^2

h = reservoir height, ft

J_H = horizontal productivity index, STB/D/PSI

J_s = specific productivity index, STB/D/PSI/ft

J_{CP} = well productivity index at constant pressure, STB/D/PSI

J_{CR} = well productivity index at constant rate, STB/D/PSI

K_h = horizontal permeability, md

K_x = permeability in x direction, md

K_y = permeability in y direction, md

K_z = permeability in z direction, md

K_{eq} = equivalent permeability, md

Kv = vertical permeability, md

L = length of horizontal well, ft

N_{Re} = Reynolds number

P_D = dimensionless pressure, dimensionless

P_e = external boundary pressure, psi

PI	= Productivity Index
P_w	= pressure in wellbore, psi
ΔP	= drawdown at the heel, psi
ΔP_f	= pressure loss due to friction, psi
P_F	= intermediate arbitrary pressure in the wellbore, psi
P_H	= pressure loss at the heel with friction loss, psi
P_H'	= pressure loss at the heel without friction loss, psi
Q	= oil production rate without friction loss, STB
Q'	= oil production rate with friction loss, STB
r_{eh}	= drainage radius for horizontal well, ft
r_e'	= equivalent drainage radius, ft
r_w	= wellbore radius, ft
r_w'	= effective wellbore radius, ft
R_{ev}	= vertical drainage radius, ft
R_s	= flow resistance of well, dimensionless
S	= skin factor, dimensionless
S_p	= skin factor due to partial penetration, dimensionless
S_m	= mechanical skin damage, dimensionless,
S_R	= skin factor due to partial penetration in areal plane, dimensionless
S_f	= skin factor, fully penetrating fracture of length L, dimensionless
$S_{CA,h}$	= shape factor skin, dimensionless
V_x	= superficial oil velocity, ft/s
Xe	= x co-ordinate of horizontal well
Ye	= y co-ordinate of horizntal well
x	= distance along the well, ft
μ_o	= oil viscosity, cp
α	= empirical cofficient for flow resistance
γ	= Euler's constant
ε	= absolute roughness, ft

ρ = density of oil, lbm/ft^3

β = anisotropy

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APPENDIX

Table A-1: Analytical Productivity Models used to compare simulated value of PI

Steady State Productivity Models	**Productivity Model**
1. Joshi Equation (1988)- Elliptical Drainage Area.	$J_h = \dfrac{0.007078 K_h h/(\mu_o B_o)}{\left[\ln\left(\dfrac{a+\sqrt{a^2+(L/2)^2}}{(L/2)}\right)+(h/L)\ln(h/2r_w)\right]}$
2. Renard and Dupuy (Elliptical Drainage Area)	$J_h = \dfrac{2\pi K_h h}{(\mu_o B_o)}\left[\dfrac{1}{\cosh^{-1}(X)+(h/L)\ln(h/2\pi r_w)}\right]$
3. Borisov Equation (1964) – Elliptical Drainage Area.	$J_h = \dfrac{2\pi K_h h/(\mu_o B_o)}{[Ln(4r_{eh}/L)+(h/L)Ln(h/2\pi r_w)]}$
Pseudosteady State Productivity Models	
4. Babu and Odeh (1989)	$J = \dfrac{7.078\times10^{-3}(2Xe)\sqrt{kykv}/(\mu oBo)}{\ln\left(\dfrac{\sqrt{A_1}}{r_w}\right)+\ln C_H - 0.75 + S_R}$
5. Wattenbarger et al (1998) Constant Bottom hole Pressure Model	$J_{CP} = \dfrac{k_{eq} b_{eq}}{141.2\mu_o B_o\left(1/2\ln\dfrac{4A_{eq}}{\gamma r_{weq}^2} - 1/2\ln C_{ACP} + S_{PCP}\right)}$
6. Economides (1994)	$J = \dfrac{kx_e}{877.22\mu_o B_o\left(P_D + \dfrac{xe}{2\pi L}\sum s\right)}$

Table A-2: Calculation of friction pressure losses using various correlations

Data	Jain	Dikken	Eclipse	Chen
Pi psia	3000	3000	3000	3000
Pwf psia	2850	2850	2850	2850
μ cp	1	1	1	1
e/D rough	0.1	0.1	0.1	0.1
Bo rb/stb	1.2	1.2	1.2	1.2
Kh md	20	20	20	20
Va acres	32	32	32	32
D ft	0.375	0.375	0.375	0.375
Kv md	2	2	2	2
Hft	50	50	50	50
L ft	4000	4000	4000	4000
S	5	5	5	5
ρ kf/m3	850	850	850	850
b	3.1622777	3.162278	3.162278	3.162278
Rev	666.27589	666.2759	666.2759	666.2759
Ah	128.0563	128.0563	128.0563	128.0563
rwe'	0.0008314	0.000831	0.000831	0.000831
Reh	1332.8448	1332.845	1332.845	1332.845
a	2162.1852	2162.185	2162.185	2162.185
cosh-1(X) =	0.4000492	0.400049	0.400049	0.400049
Q'	1160.4694	1160.469	1160.469	1160.469
Rs	4.101E-06	4.1E-06	4.1E-06	4.1E-06
Js(x)	0.0023209	0.002321	0.002321	0.002321
Qx=0	1077.3817	1077.382	1077.382	1077.382
Vx	0.7611227	0.761123	0.761123	0.761123
Nre	18764.163	18764.16	18764.16	18764.16
f	0.0257799	0.00675	0.073255	0.025606
dpw/dx	0.1479555	0.038739	0.420425	0.146958
dPf(X)x=L	4.109876	1.076074	11.67846	4.082155
J's	7.7364628	7.736463	7.736463	7.736463
Js	6.9909972	7.131385	6.663731	6.992255